STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

DOCKET NOS. 2019-185-E, 2019-186-E

In the Matter of: South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 58-41-20(A), and South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Progress, LLC's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 58-41-20(A)	)	DIRECT TESTIMONY OF JAMES F. WILSON ON BEHALF OF SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND SOUTHERN ALLIANCE FOR CLEAN ENERGY

I. INTRODUCTION AND QUALIFICATIONS

Q: Please state your name, position and business address for the record.

A: My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814.

Q: Please describe your experience and qualifications.

A: I have thirty-five years of consulting experience, primarily in the electric power and natural gas industries. Many of my assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients.

With respect to the resource adequacy issues I will address in this testimony, I have been actively involved in these issues in the PJM Interconnection, L.L.C. ("PJM") region for many years, participating in PJM stakeholder processes, performing and presenting analysis of these issues, and submitting affidavits in various regulatory proceedings. I have also been involved in these issues in various state regulatory proceedings, most recently in North Carolina.

I have submitted affidavits and presented testimony in proceedings of the FERC, state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is attached as Exhibit A.

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of the South Carolina Coastal Conservation League and the Southern Alliance For Clean Energy.

Q: Are you sponsoring any exhibits?

A: Yes. I am sponsoring an expert report, *Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing*, included as Exhibit B.

Q: What is the purpose of your direct testimony in this proceeding?

A: Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Companies" or "Duke Energy") have proposed new Schedule PP avoided capacity credits with modified seasonal and hourly structures. The seasonal weighting and other aspects of the proposed rates and rate design were based upon resource adequacy studies ("DEC 2016 RA Study", "DEP 2016 RA Study"; collectively "2016 RA Studies") that were prepared for DEC and DEP by Astrapé Consulting in 2016.[1] The capacity values for solar resources were based

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[1] Response to Data Request SACE – SCCL 1-17 (confirming that the rate designs proposed by Duke Energy in this proceeding are identical to the rate designs proposed in a stipulation filed with the North Carolina Public Staff in NC Utilities Commission Docket No. E-100 Sub 158 on April 18, 2019), Exhibit C; Stipulation of Partial Settlement Among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and the Public Staff, N.C. Utilities Commission Docket No. E-100 Sub 158 (Apr. 18, 2019), *available at* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=fb7eb61d-d511-4002-b723-ae348db80a1a ("The Stipulating Parties agree that it is reasonable and appropriate for the Companies' seasonal and hourly allocations of capacity payments *to be based upon the loss of load risk identified in the Astrapé Capacity Value of Solar study*, as filed in support of the Companies' 2018 Integrated Resource Plans, in Docket No. E-100, Sub 157") (emphasis added); Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study, August 27, 2018 (hereinafter "*Solar Capacity Value Study*") pp. 16, 34, Exhibit D (relying on 2016 RA Studies); NCSEA's Initial Comments, Attachment 4 (filed copy of *Solar Capacity Value Study*), N.C. Utilities Commission Docket No. E-100 Sub 158 (Feb. 12, 2019), *available at* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=e3e78a9d-d4db-4be5-814e-c798ebd506c3.

on the Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study ("Solar Capacity Value Study"), which employs the same model and many of the same assumptions that were used in the 2016 RA Studies.[2]

I have reviewed and evaluated the 2016 RA Studies and Solar Capacity Value Study and provide recommendations with regard to the proposed avoided capacity rate design. I also comment on the implications of the various shortcomings in the 2016 RA Studies and the Solar Capacity Value Study for the projection of seasonal loss of load risk, seasonal capacity values, and avoided cost rate design.

II. REVIEW OF DUKE ENERGY'S RESOURCE ADEQUACY STUDIES AND SOLAR CAPACITY VALUE STUDY

Q: Please summarize Duke Energy's proposed avoided capacity rate design.

A: DEP proposes a 100%/0% winter/summer capacity payment weighting, and DEC proposes 90%/10%, citing to their 2018 Integrated Resource Plans.[3] The Companies also propose changes to the monthly and hourly structures. The Companies' proposals rely on analyses used for their 2018 IRP, including the Solar Capacity Value Study and the 2016 RA Studies that attempted to reflect the recent experience with extreme cold temperatures and also higher solar penetrations.

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[2] *Solar Capacity Value Study* at pp. 16-20 ("To model the effects of weather uncertainty, 36 historical weather years (1980 – 2015) were developed to reflect the impact of weather on load. These were the same 36 load shapes used in the 2016 Resource Adequacy Study.").

[3] *See* Direct Testimony of Glen A. Snider (hereinafter "Snider Direct Testimony") at p. 19 (describing proposed seasonal allocation and link to IRP); *see also* Joint Application of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, at pp. 13-14 ("[T]he Companies' rate design also reflects seasonal allocation weightings for capacity payments based on the impact of summer versus winter loss of load risk.").

Q: Have you reviewed Duke Energy's witness testimony with regard to the proposed avoided capacity rates and rate design?

A: Yes I have.

Q: Please describe your expert report included as Exhibit B.

A: The report attached as Exhibit B documents my review and evaluation of the 2016 RA Studies and Solar Capacity Value Study. I initially performed this review and evaluation in the context of pending avoided cost proceedings in North Carolina.[4]

Q: Has the North Carolina Public Utilities Commission ("NCUC") taken any actions with regard to the issues raised in your report?

A: Yes. In the NCUC's recent Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses in the E-100, Sub 157 proceeding ("2018 NC IRP Order"), the NCUC stated that it "does not accept some of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020."[5] The 2018 NC IRP Order scheduled an oral argument for January 8, 2020 to further consider issues surrounding Duke Energy's load forecasts and reserve margins, including the concerns I raised.[6]

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[4] *See* Initial Comments of the Southern Alliance for Clean Energy, North Carolina Utilities Commission Docket No. E-100 Sub 158, Attachment B (Feb. 12, 2019), *available at* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=9d229c61-17de-44a3-985d-f449a12cea5a.
[5] Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analysis, Docket No. E-100, Sub 157, at p. 7 (Aug. 27, 2019), *available at* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=143d85de-b1e7-4622-b612-5a8c77e909d4.
[6] *Id.* at p. 89, Appendix A, pp. 1-3.

Q: Are your findings as documented in Exhibit B applicable to this proceeding?

A: Yes. Exhibit B evaluates the same RA Studies and Solar Capacity Value Study that are used by Duke Energy to support the proposed avoided capacity rate design filed in this proceeding.

The findings documented in Exhibit B are also relevant to Duke Energy's proposed solar integration services charge ("SISC"). Astrapé Consulting calculated the proposed SISC in its DEC and DEP Solar Ancillary Services Study, which relies on the same flawed load shapes as used in the 2016 RA Studies.[7]

Q: Please provide an overview of the primary issues you have identified with the RA Studies and Solar Capacity Value Study.

A: My analysis, documented in Exhibit B, shows that the risk of very high loads under extreme cold was significantly overstated in the 2016 RA Studies, primarily due to the faulty approach Astrapé Consulting used to extrapolate the relationship between temperature and load to very low temperatures. Winter resource adequacy risk was also overstated due to the demand response and operating reserve assumptions applicable to winter peak conditions. Overall, the winter resource adequacy risk was substantially overstated relative to the risk in summer and other periods of the year.

Both winter and summer risk were further overstated due to the economic load forecast uncertainty assumptions, which greatly overstate the risk of large and unexpected increases in peak load.

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[7] Direct Testimony of Nick Wintermantel, Exhibit 2 at p. 14 (filed copy of DEC and DEP Solar Ancillary Services Study), Docket Nos. 2019-185-E and 2019-186-E.

I also note that the Companies' approach to estimating seasonal, monthly and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins will be highly sensitive to various assumptions that can change dramatically over just a few years. This suggests that a fixed rate design, such as reflected in Schedule PP, should not be overly focused on relatively few months of the year or hours of the day, because the Companies' estimates of the seasons and hours with resource adequacy risk can change over time as load shapes and the resource mix change. Additionally, the price signals inherent in the rate design can shift capacity needs to adjacent hours or months. While it is important to strive for accurate price signals, it is also important to strive for price signals that are reasonably stable over time, and likely to remain reasonably accurate as conditions change.

III. RECOMMENDATIONS

Q: What is your recommendation with regard to the Companies' proposed seasonal weightings?

A: Due to the flaws noted above, I recommend that the winter/summer capacity values proposed for use in the avoided capacity cost weightings (100%/0%, 90%/10%) in the Companies' Schedule PP be rejected, and much more balanced seasonal weights developed and approved.

Q: What is your recommendation with regard to the proposed hourly and monthly capacity?

A: Because the Companies' proposed Schedule PP rate designs are based on the same flawed analysis that is highly sensitive to various questionable assumptions, I also recommend rejecting the proposed monthly and hourly rate structures.

Q: Do you recommend specific seasonal weightings, or monthly and hourly rate structures?

A: No. This would require use of the Companies' modeling tools to perform further analysis after correcting the flaws identified above (estimated loads under extreme cold; demand response and operating reserve assumptions; and load forecast uncertainty).

Q: Does this complete your direct testimony?

A: Yes it does.

Exhibit A

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Principal, Wilson Energy Economics

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SUMMARY

James F. Wilson is an economist with over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982

BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.
- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.

- Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
- Participated in a panel teleseminar on resource adequacy policy and modeling.
- Affidavit on opt-out rules for centralized capacity markets.
- Affidavits on minimum offer price rules for RTO centralized capacity markets.
- Evaluated electric utility avoided cost in a tax dispute.
- Advised on pricing approaches for RTO backstop short-term capacity procurement.
- Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
- Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
- Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
- Participated on a panel teleseminar on natural gas price forecasting.
- Affidavit evaluating a shortage pricing mechanism and recommending changes.
- Testimony in support of proposed changes to a forward capacity market mechanism.
- Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
- Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
- Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
- Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE

LECG, LCC, Washington, DC 1998–2009.
<u>Principal</u>

- Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
- Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
- Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
- Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism's design; prepared a detailed report. Evaluated the impacts of the mechanism's flaws on prices and costs and prepared testimony in support of a formal complaint.
- Analyzed impacts and potential damages of natural gas migration from a storage field.
- Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
- Prepared affidavit evaluating a pipeline's application for market-based rates for interruptible transportation and the potential for market power.
- Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
- Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.
- Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
- Evaluated market power issues raised by a possible gas-electric merger.
- Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission ("FERC") policy.

- Prepared an expert report on damages in a natural gas contract dispute.
- Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
- Prepared testimony evaluating natural gas procurement incentive mechanisms.
- Analyzed the need for and value of additional natural gas storage in the southwestern US.
- Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
- Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
- Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
- Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
- Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
- Advised a major US utility with regard to the Federal Energy Regulatory Commission's proposed Standard Market Design and its potential impacts on the company.
- Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
- Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
- Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
- Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.
- Reviewed the reasonableness of an electric utility's wholesale power purchases and sales in a restructured power market during a period of high prices.
- Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
- Presented a workshop on Market Monitoring to a group of electric utilities in the process of forming an RTO.
- Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
- Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
- Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
- Authored a report on the role of regional transmission organizations in market monitoring.
- Prepared market power analyses in support of electric generators' applications to FERC for market-based rates for energy and ancillary services.
- Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
- Testified before a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.
- Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
- Advised a California utility regarding reform strategies for the California natural gas industry, addressing market power issues and policy options for providing system balancing services.

ICF RESOURCES, INC., Fairfax, VA, 1997–1998.
Project Manager

- Reviewed, critiqued and submitted testimony on a New Jersey electric utility's restructuring proposal, as part of a management audit for the state regulatory commission.
- Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy's Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility's generation assets and entitlements (power purchase agreements).
- Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.

IRIS MARKET ENVIRONMENT PROJECT, 1994–1996.
Project Director, Moscow, Russia

Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (*the Program on Natural Monopolies,* a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID):

- Advised on industry reforms and the establishment of federal regulatory institutions.
- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
- Developed policy conditions for the IMF's $10 billion Extended Funding Facility.
- Performed industry diagnostic analyses with detailed policy recommendations for electric power (1994), natural gas, rail transport and telecommunications (1995), oil transport (1996).

Independent Consultant stationed in Moscow, Russia, 1991–1996

Projects for the WORLD BANK, 1992-1996:

- Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
- Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.
- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.

Other consulting assignments in Russia, 1991–1994:

- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992
Senior Associate*,* 1985-1992*.*

- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
- Analyzed long term coal and rail alternatives for a midwest electric utility.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- Performed a financial and economic analysis of a proposed hydroelectric project.
- For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes. Developed a forecasting system for staff use.
- Analyzed potential benefits of diversification of suppliers for a natural gas pipeline company.
- Evaluated uranium contracting strategies for an electric utility.
- Analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' telecommunications services and prices.
- Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
- Analyzed oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2019 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-20221, Direct Testimony on behalf of Michigan Environmental Council, May 28, 2019.

PJM Interconnection, L.L.C., FERC Docket Nos. EL19-58 and ER19-1486 (Reserve Pricing - ORDC), Affidavit in Support of the Protest of the Clean Energy Advocates, May 15, 2019.

PJM Interconnection, L.L.C., FERC Docket Nos. EL19-58 and ER19-1486 (Reserve Pricing - Transition), Affidavit in Support of the Protests of the PJM Load/Customer Coalition and Clean Energy Advocates, May 15, 2019.

In Re: Georgia Power Company's 2019 Integrated Resource Plan, Georgia Public Service Commission Docket No. 42310, Direct Testimony on Behalf of Georgia Interfaith Power & Light and the Partnership For Southern Equity, April 25, 2019; testimony at hearings May 14, 2019.

PJM Interconnection, L.L.C., FERC Docket No. EL19-63 (RPM Market Supplier Offer Cap), Affidavit in Support of the Complaint of the Joint Consumer Advocates, April 15, 2019.

In the Matter of 2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans, North Carolina Utilities Commission Docket No. E-100 Sub 157, Review and Evaluation of the Load Forecasts, and Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues, with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans, Attachments 3 and 4 to the comments of Southern Alliance for Clean Energy, Sierra Club, and the Natural Resources Defense Council, March 7, 2019.

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018, North Carolina Utilities Commission Docket No. E-100 Sub 158, Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing, Attachment B to the Initial Comments of the Southern Alliance for Clean Energy, February 12, 2019.

PJM Interconnection, L.L.C., FERC Docket No. ER19-105 (RPM Quadrennial Review), Affidavit in Support of the Limited Protest and Comments of the Public Interest Entities, November 19, 2018.

PJM Interconnection, L.L.C., FERC Docket No. EL18-178 (MOPR and FRR Alternative), Affidavit in Support of the Comments of the FRR-RS Supporters, October 2, 2018; Reply Affidavit on behalf of Clean Energy and Consumer Advocates, November 6, 2018.

Virginia Electric and Power Company's 2018 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2018-00065, Direct Testimony on behalf of Environmental Respondents, August 10, 2018; testimony at hearings September 25, 2018; Supplemental Testimony, April 16, 2019.

In the Matter of the Application of Duke Energy Ohio for an Increase in Electric Distribution Rates, etc., Public Utilities Commission of Ohio Case No. 17-32-EL-AIR et al, Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, June 25, 2018; deposition, July 3, 2018; testimony at hearings, July 19, 2018.

In the Matter of the Application of DTE Gas Company for Approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 Months ending March 31, 2019, Michigan Public Service Commission Case No. U-18412, Direct Testimony on behalf of Michigan Environmental Council, June 7, 2018.

Constellation Mystic Power, L.L.C., FERC Docket No. ER18-1639-000 (Mystic Cost of Service Agreement), Affidavit in Support of the Comments of New England States Committee on Electricity, June 6, 2018; prepared answering testimony, August 23, 1018.

New England Power Generators Association, Complainant v. ISO New England Inc. Respondent, FERC Docket No. EL18-154-000 (re: capacity offer price of Mystic power plant), Affidavit in Support of the Protest of New England States Committee on Electricity, June 6, 2018.

PJM Interconnection, L.L.C., FERC Docket No. ER18-1314 (Capacity repricing or MOPR-Ex), Affidavit in Support of the Protests of DC-MD-NJ Consumer Coalition, Joint Consumer Advocates, and Clean Energy Advocates, May 7, 2018; reply affidavit, June 15, 2018.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2018 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-18403, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, April 20, 2018.

Virginia Electric and Power Company's 2017 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2017-00051, Direct Testimony on behalf of Environmental Respondents, August 11, 2017; testimony at hearings September 26, 2017.

Ohio House of Representatives Public Utilities Committee hearing on House Bill 178 (Zero Emission Nuclear Resource legislation), Opponent Testimony on Behalf of Natural Resources Defense Council, May 15, 2017.

In the Matter of the Application of Atlantic Coast Pipeline, Federal Energy Regulatory Commission Docket No. CP15-554, Evaluating Market Need for the Atlantic Coast Pipeline, Attachment 2 to the comments of Shenandoah Valley Network *et a*l, April 6, 2017.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2017 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-18143, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, March 22, 2017.

In the Matter of the Petition of Washington Gas Light Company for Approval of Revised Tariff Provisions to Facilitate Access to Natural Gas in the Company's Maryland Franchise Area That Are Currently Without Natural Gas Service, Maryland Public Service Commission Case No. 9433, Direct

Testimony on Behalf of the Mid-Atlantic Propane Gas Association and the Mid-Atlantic Petroleum Distributors Association, Inc., March 1, 2017; testimony at hearings, May 1, 2017.

In the Matter of Integrated Resource Plans and Related 2016 REPS Compliance Plans, North Carolina Utilities Commission Docket No. E-100 Sub 147, Review and Evaluation of the Peak Load Forecasts and Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans, Attachments A and B to the comments of the Natural Resources Defense Council, Southern Alliance for Clean Energy, and the Sierra Club, February 17, 2017.

In the Matter of the Tariff Revisions Designated TA285-4 filed by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., Regulatory Commission of Alaska Case No. U-16-066, Testimony on Behalf of Matanuska Electric Association, Inc., February 7, 2017, testimony at hearings, June 21, 2017.

PJM Interconnection, L.L.C., FERC Docket No. ER17-367 (seasonal capacity), Prepared Testimony on Behalf of Advanced Energy Management Alliance, Environmental Law & Policy Center, Natural Resources Defense Council, Rockland Electric Company and Sierra Club, December 8, 2016; Declaration in support of Protest of Response to Deficiency Letter, February 13, 2017.

Natural Resources Defense Council, Sierra Club, and Union of Concerned Scientists v. Federal Energy Regulatory Commission, U.S. District Court of Appeals for the D.C. Circuit Case No. 16-1236 (Capacity Performance), Declaration, September 23, 2016.

Mountaineer Gas Company Infrastructure Replacement and Expansion Program Filing for 2016, West Virginia Public Service Commission Case No. 15-1256-G-390P, and Mountaineer Gas Company Infrastructure Replacement and Expansion Program Filing for 2017, West Virginia Public Service Commission Case No. 16-0922-G-390P, Direct Testimony on behalf of the West Virginia Propane Gas Association, September 9, 2016.

Application of Chesapeake Utilities Corporation for a General Increase in its Natural Gas Rates and for Approval of Certain Other Changes to its Natural Gas Tariff, Delaware P.S.C. Docket No. 15-1734, Direct Testimony on behalf of the Delaware Association Of Alternative Energy Providers, Inc., August 24, 2016.

Virginia Electric and Power Company's 2016 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2016-00049, Direct Testimony on behalf of Environmental Respondents, August 17, 2016; testimony at hearings October 5, 2016.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2016 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-17920, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, March 14, 2016.

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PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

May 2019

Exhibit B

Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing

James F. Wilson, Wilson Energy Economics
Prepared on behalf of the Southern Environmental Law Center
February 12, 2019

I. INTRODUCTION AND SCOPE OF THIS REPORT

1. Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Companies" or "Duke") filed their 2018 Integrated Resource Plans ("2018 IRP") on September 5, 2018 in Docket No. E-100 Sub 157. The Companies filed their proposed Avoided Cost tariffs ("2018 Avoided Cost Filing") on November 1, 2018 in Docket No. E-100 Sub 158. The 2018 IRPs present load forecasts (Chapter 3) and recommended reserve margins (Chapter 8) that serve as the basis for each utility's determination of the total generating capacity required over the IRP planning horizon. This capacity need is reflected in the capacity values for solar resources (IRP Chapter 9).

2. The reserve margins used in the 2018 IRPs were based upon recommendations from resource adequacy studies ("DEC 2016 RA Study", "DEP 2016 RA Study"; collectively "2016 RA Studies") that were prepared for DEC and DEP by Astrapé Consulting in 2016, and were also used for the DEC and DEP 2016 IRPs. The capacity values for solar resources were based on an Astrapé report[1] that employs the same model and many of the same assumptions that were used in the 2016 RA Studies. The 2018 Avoided Cost Filing proposes new Schedule PP avoided capacity credits with modified seasonal and hourly structures based on the Astrapé analyses.

3. In a report filed on February 17, 2017 in Docket No. E-100 Sub 147 ("Wilson 2017 RM Report"), I reviewed and evaluated the 2016 RA Studies, raising a number of issues with the Studies' assumptions and methodologies. In this current report I re-

[1] Response to Data Request SACE/NRDC/Sierra Club 1-28, *Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study*, August 27, 2018 ("Capacity Value Study").

evaluate the reserve margins used in the 2018 IRPs and the 2016 RA Studies that formed the basis for them with the benefit of additional analysis and data that have become available since the Wilson 2017 RM Report. I also comment on the implications of the various shortcomings in the 2016 RA Studies and the related Capacity Value Study for the projection of seasonal loss of load risk, seasonal capacity values, and avoided cost rate design. The focus in this report is on demand-side assumptions, including load patterns and demand response; supply-side assumptions, including solar modeling, were outside the scope of this report. The load forecasts used in the 2018 IRPs are the subject of a separate Wilson Energy Economics report.

II. BACKGROUND

4. In its final order on the 2016 IRPs, the North Carolina Utilities Commission ("NCUC" or "Commission") concluded that the proposed reserve margins included in the 2016 IRPs were "reasonable at this time for planning purposes", but also concluded that the proposed move to a 17% winter reserve margin target was "not supported by the evidence."[2] The order called for DEC and DEP to work with the Public Staff to address the concerns raised by the Public Staff and in the Wilson 2017 RM Report, and to "implement changes as necessary to help ensure that the reserve margin target(s) are fully supported in future IRPs."

5. In its final order in the 2016 avoided cost docket, the Commission accepted Duke's proposed seasonal capacity weighting of 80% winter and 20% summer for determining the avoided capacity rates, noting that the proposal relied upon the 2016 RA Studies, and stating that the Commission would be receptive to revisiting the seasonal capacity weighting in future avoided cost cases.[3]

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[2] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans*, Docket No. E-100, Sub 147, June 27, 2017 at 21-22.

[3] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 148, October 11, 2017 at 59.

6. On April 2, 2018 in the 2016 IRP docket, the Public Staff filed a joint report of the Public Staff, DEC and DEP addressing the reserve margin issues ("Joint Report"), to which was attached a Duke presentation to the Public Staff: *2016 Resource Adequacy Study – Outstanding Issues*, December 12, 2017 ("December 2017 Presentation"). In an order issued April 16, 2018, the Commission accepted the Joint Report, noting that the Public Staff and DEC and DEP did not reach consensus on all of the issues they discussed. The Companies' views on these issues were also reflected in their May 10, 2017 Reply in the same docket.

III. SUMMARY AND RECOMMENDATIONS

7. Both 2018 IRPs recommend a 17% winter planning reserve margin (p. 8), based on the 2016 RA Studies (p. 6), which is an increase relative to the reserve margins used before the 2016 IRPs. The Avoided Cost Filing proposes a 100%/0% winter/summer capacity payment weighting for DEP, and 90%/10% for DEC, citing to the 2018 IRPs (Table 9-B), which recommendation is also based on the 2016 RA Studies and related Capacity Value Study. (p. 29) These recommendations are based on analysis that attempts to reflect the recent experience with extreme cold temperatures and also higher solar penetration (2018 IRP, p. 38).

8. The evaluation performed for this report focused on the following issues with regard to the 2016 RA Studies and Capacity Value Study:

a. The representation of some very extreme winter loads, based on an extrapolation of the relationship between cold temperatures and winter loads;
b. The "economic load forecast uncertainty" layered on top of the weather-related load distributions;
c. The assumptions regarding future winter demand response capacity; and
d. The assumptions regarding operating reserves during brief load spikes on extremely cold winter mornings.

9. This report shows that the risk of very high loads under extreme cold was substantially overstated in the 2016 RA Studies, primarily due to the faulty approach to extrapolating the increase in load due to very low temperatures. Winter resource adequacy risk was also overstated due to the demand response and operating reserve assumptions applicable to winter peak conditions. Overall, the winter resource adequacy risk was substantially overstated relative to the risk in summer and other periods of the year. Accordingly, the winter/summer capacity values of solar resources proposed for use in the 2018 IRPs (Tables 9-B and 9-C, pp. 45-46), as well as the avoided capacity cost weightings (100%/0%, 90%/10%) proposed for use in the Companies' Schedule PP filed in Docket No. E-100, Sub 158, should be rejected, and much more balanced seasonal weights developed and approved.

10. Both winter and summer risk were further overstated due to the economic load forecast uncertainty assumptions, which greatly overstate the risk of large and unexpected increases in peak load. Due to this error as well as the overstatement of winter resource adequacy risk, I again conclude that the recommended increases in the DEC and DEP reserve margins (relative to IRPs before 2016) are unsupported and unnecessary.

11. I also note that the Companies' approach to estimating seasonal, monthly and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins will be highly sensitive to various assumptions that can change dramatically over just a few years. This suggests that a fixed rate design, such as reflected in Schedule PP, should not be overly focused on relatively few months of the year or hours of the day, because the Companies' estimates of the seasons and hours with resource adequacy risk can change over time as load shapes and the resource mix change. Additionally, the price signals inherent in the rate design can shifts capacity needs to adjacent hours or months. While it is important to strive for accurate price signals, it is also important to strive for price signals that are reasonably stable over time, and likely to remain reasonably accurate as conditions change. Because the Companies' proposed Schedule PP rate designs are based on the same flawed analysis that is highly

sensitive to assumptions, I also recommend rejecting the proposed monthly and hourly rate structures.

12. I do not recommend specific seasonal weightings, monthly and hourly rate structures, or reserve margins, as this would require use of the Companies' modeling tools to perform further analysis with the flaws identified above corrected.

13. The analysis documented in this report was again hampered by incomplete responses to some data requests and a lack of details and sensitivity analyses with regard to the 2016 RA Studies. Appendix A to this report further discusses the importance of access to the full details of such analyses, and provides recommendations for future IRPs.

14. The remainder of this report is organized as follows. Section IV discusses the four issues with the 2016 RA Studies and Capacity Value Study that overstate winter risk and required reserve margins. Section V summarizes findings and recommendations, including recommendations for future IRPs. Appendix A lists additional information that was sought but not provided. Appendix B summarizes the author's qualifications.

IV. CRITIQUE OF THE 2016 RA STUDIES AND CAPACITY VALUE STUDY

15. The 2016 RA Studies document a probabilistic simulation of load and resources to find the planning reserve margin required to satisfy a "one day in ten years" ("1-in-10") resource adequacy criterion, equivalent to an annual Loss of Load Expectation ("LOLE") of 0.1 events per year. The Capacity Value Study applies the same model logic and load modeling methodology, and many other common assumptions, to evaluate various levels of solar penetration.[4] The 2016 RA Studies and Capacity Value Study determine certain months and hours of the year in which risk of loss of load occurs, according to the specific assumptions used in each study.

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[4] Response to Data Request SACE/NRDC/Sierra Club 4-6.

A. Representing The Impact Of Extreme Cold On Winter Peak Loads

16. In recent years, brief periods of extreme cold have resulted in very high loads on the DEC and DEP systems. To accurately evaluate winter period resource adequacy, it was appropriate for the 2016 RA Studies to model extreme cold and its impact on load levels. The same representation of load was used in the Capacity Value Study.

17. In the winters of 2014 and 2015 there were a few days colder than any that had occurred in the DEC and DEP-East service territories since 1996. Based on the temperature data used for the DEC RA Study,[5] 2014 and 2015 each had two days in which temperatures dropped below 10 degrees Fahrenheit; in the years before 2014, temperatures had not dropped to even 11 degrees since 1996. However, the 2016 RA Studies used 36 years of historical weather data, back to 1980, and even lower temperatures were seen in some years in the 1980s (3, 4, and 5 degrees in 1982, 1983, and 1986, respectively, and minus 5 in 1985). Therefore, to use 36 years of weather data it was necessary to model loads under temperatures below any that had been seen in the last 30 years.

18. The 2016 RA Studies determined load levels under extreme cold conditions applying a very simple regression analysis to recent data.[6] The regressions consider only temperature (not wind speeds), and focus on temperatures in the 18-25 degree range (DEP East; 18-22 for DEC), for which observations are plentiful. Based on the regression, the DEC RA Study estimated the DEC load, under extreme cold conditions, with the following linear equation:

DEC Load (MW) = -231 * (Temperature) + 20,372.

19. This equation implies that under extreme cold conditions, for each degree the temperature falls, DEC's load is assumed to increase by 231 MW (roughly 1.3%). Four

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[5] Response to Data Request NCSEA 3-12 in Docket No. E-100 Sub 158.

[6] Response to Data Request SACE/NRDC/Sierra Club 3-1 attachment. This attachment includes the original regressions from the 2016 RA Studies.

additional degrees results in 924 MW of additional load (over 5% increase). A similar equation was derived for DEP East loads, that suggested 228 MW per degree.

20. The Wilson 2017 RM Report criticized this approach, providing analysis showing that for lower temperatures, the relationship between temperature and load was much weaker than this equation suggests. This is logical -- once temperatures drop to the teens, customers may have turned on all of the equipment that will help them stay warm, and further declines in temperature do not increase loads as much. In addition, some schools, offices, and other commercial, government and industrial facilities may close, reduce operations, or open late due to extreme cold conditions, reducing loads during the morning peak.

21. The fact that beyond some point further cold does not have as great an impact on load was quantified in Figures JFW-1 and JFW-2 in the Wilson 2017 RM Report. In particular, the analysis shown in Figure JFW-1 of that report showed that for temperatures under 17 degrees, DEC load only increased 108 MW, not 231 MW, for each additional degree.

22. The Joint Report did not address the inaccuracy of the regressions used in the 2016 RA Studies. The Joint Report notes the issue of the regression equations, and then states, "After meeting with the Company, the Public Staff was satisfied that this approach was reasonable." (p. 2)

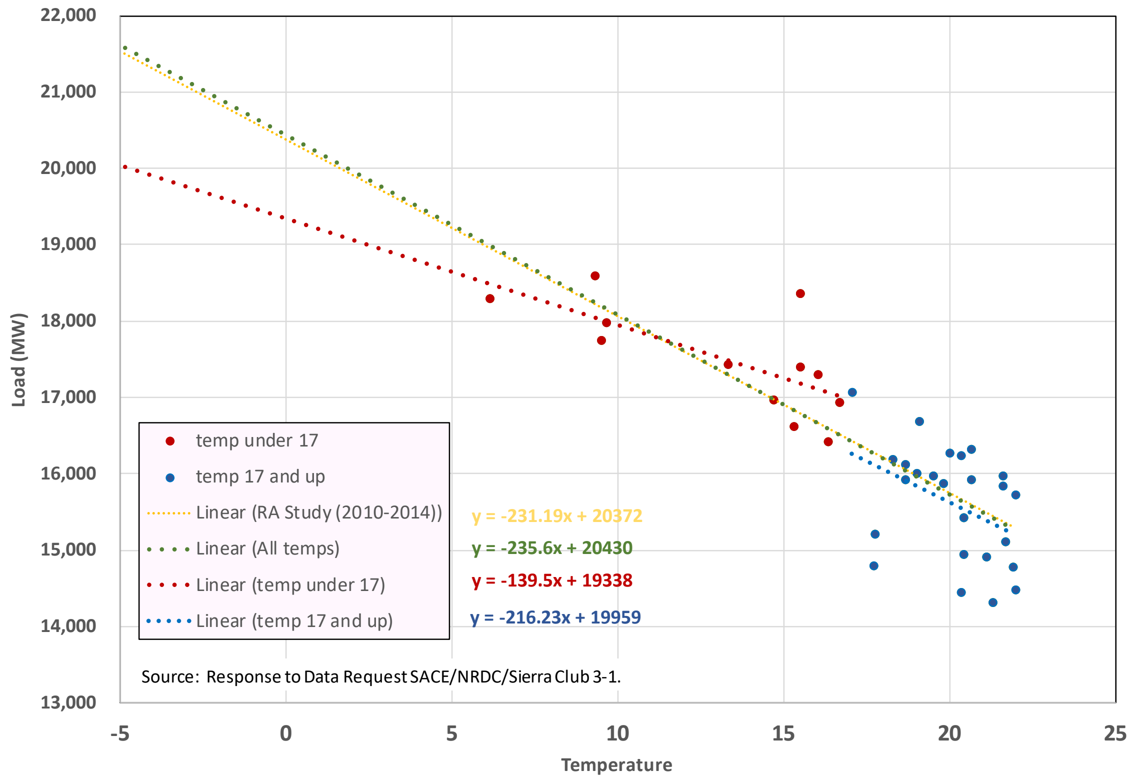
23. The December 2017 Presentation that was attached to the Joint Report claimed that "use of more current data would suggest a similar load response to temperature" for both DEC and DEP. (pp. 11-12) However, with the additional data, it also remains true that the impact of extreme cold on load is much weaker at lower temperatures, so the regressions used in the RA Studies are inaccurate for lower temperatures.

24. The regressions for the 2016 RA Studies were based on data from 2010 through 2014; for the December 2017 Presentation, data for 2015, 2016 and 2017 was

added.[7] The Companies' updated regressions, now with data through 2017, produce similar results to those in the 2016 RA Studies.

25. I updated the analysis I performed in the Wilson 2017 RM Report using this updated data set, and got very similar results – the relationship between extreme cold and load is much weaker for the lower temperatures. The results are shown in Figures JFW-1 and JFW-2. For DEC, across the entire temperature range, the relationship suggests 235.6 MW of additional load per degree, as shown in the green line in Figure JFW-1 and its regression equation. However, for temperatures below 17 degrees, the relationship is only 139.5 MW per degree (red line and equation). And it is likely that even this value (139.5 MW per degree) overstates the impact of the most extreme temperatures on loads, when, as suggested above, space heating appliances are already in full use and some facilities are remaining closed or opening late.

Figure JFW-1: DEC Winter Peak Load Regression (2010 to 2017)



Source: Response to Data Request SACE/NRDC/Sierra Club 3-1.

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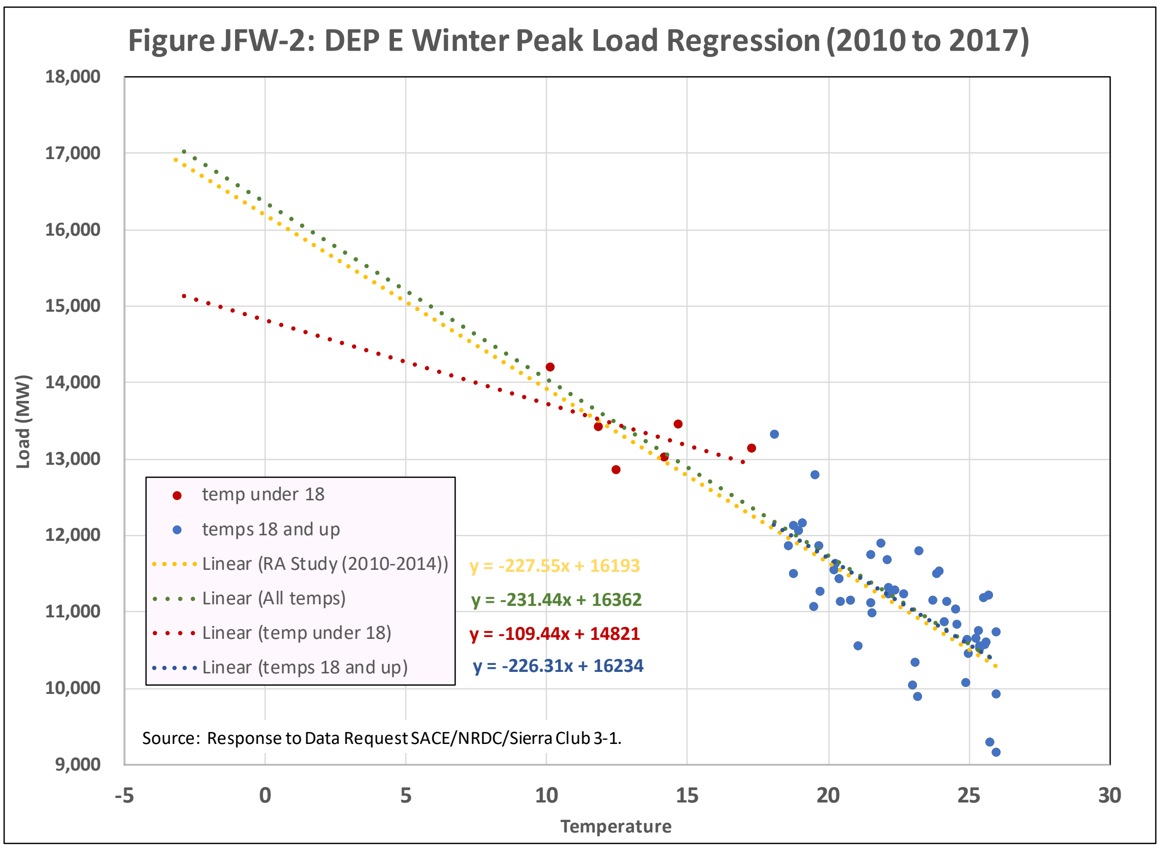
[7] Response to Data Request SACE/NRDC/Sierra Club 3-1 attachment.

26. The 36-year data set used in the DEC RA Study includes temperatures as low as minus 5 degrees. As the trend lines in Figure JFW-1 suggest, extrapolating based on all observations (green and yellow lines) leads to over 21,500 MW at minus 5 degrees, while extrapolating based on temperatures below 17 degrees (red line) leads to an estimated 20,000 MW load (which is probably still too high). I again conclude that the DEC RA Study greatly overstates loads under extreme cold conditions. This has a substantial impact on the DEC RA Study – of the simulated hours with load loss, most result from scenarios under which the winter extrapolated load exceeded 20,000 MW, even before the economic load forecast uncertainty was reflected.[8]

27. Figure JFW-2 presents the updated analysis for DEP East, which leads to the same conclusion (the red line and equation) – after a point, as temperatures drop further, the impact on load is much weaker. Compared to over 200 MW per degree for



[8] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment (discussed below).

temperatures in the 20s, below 18 degrees the relationship is 109.4 MW per degree. Again, the impact would likely be even weaker at lower temperatures, if data were available, so even 109.4 MW per degree likely results in overstating the loads at the lowest temperatures.

28. The 36-year data set used in the DEP RA Study includes temperatures below minus 3 degrees for DEP East. As the trend lines in Figure JFW-2 suggest, extrapolating based on all observations (green and yellow lines) leads to 17,000 MW at minus 3 degrees, while extrapolating based on temperatures below 18 degrees (red line) leads to just over 15,000 MW (which is probably still too high). In the DEP RA Study, two-thirds of the simulated hours with load loss were based on winter extrapolated loads in excess of 15,000 MW.[9] I again conclude that the DEP RA Study greatly overstates loads under extreme cold conditions.

29. The 231 MW per degree assumption for DEC, and 228 MW per degree assumption for DEP East, used in the 2016 RA Studies resulted in some very extreme peaks under the very cold conditions represented in some of the 36 weather years. Figure JFW-3 shows figures from the 2016 RA Studies illustrating how high winter peaks are assumed to go, as a result of the regression equations. While the extreme cold in 2014 and 2015 resulted in extreme peak loads roughly 5% to 8% above the anticipated, normal winter peak loads in those years, the 231 MW per degree assumption for DEC results in modeling peaks in the 1982 weather year 18% above the anticipated winter peak (for 2019, the year that is the focus of the 2016 RA Studies, 18% equates to over 3,300 additional MW). Modeling such extreme peaks will, of course, drive the winter reserve margin higher, and increase winter resource adequacy risk relative to summer risk. Using more realistic estimates would bring these extreme peaks down considerably. Figure JFW-3 also shows the similar graphic from the DEP RA Study, which also reflects very extreme winter peaks (over 20% above the normal winter peaks) based on the unrealistic estimates of the relationship between extreme cold and load. Figure JFW-3 also shows

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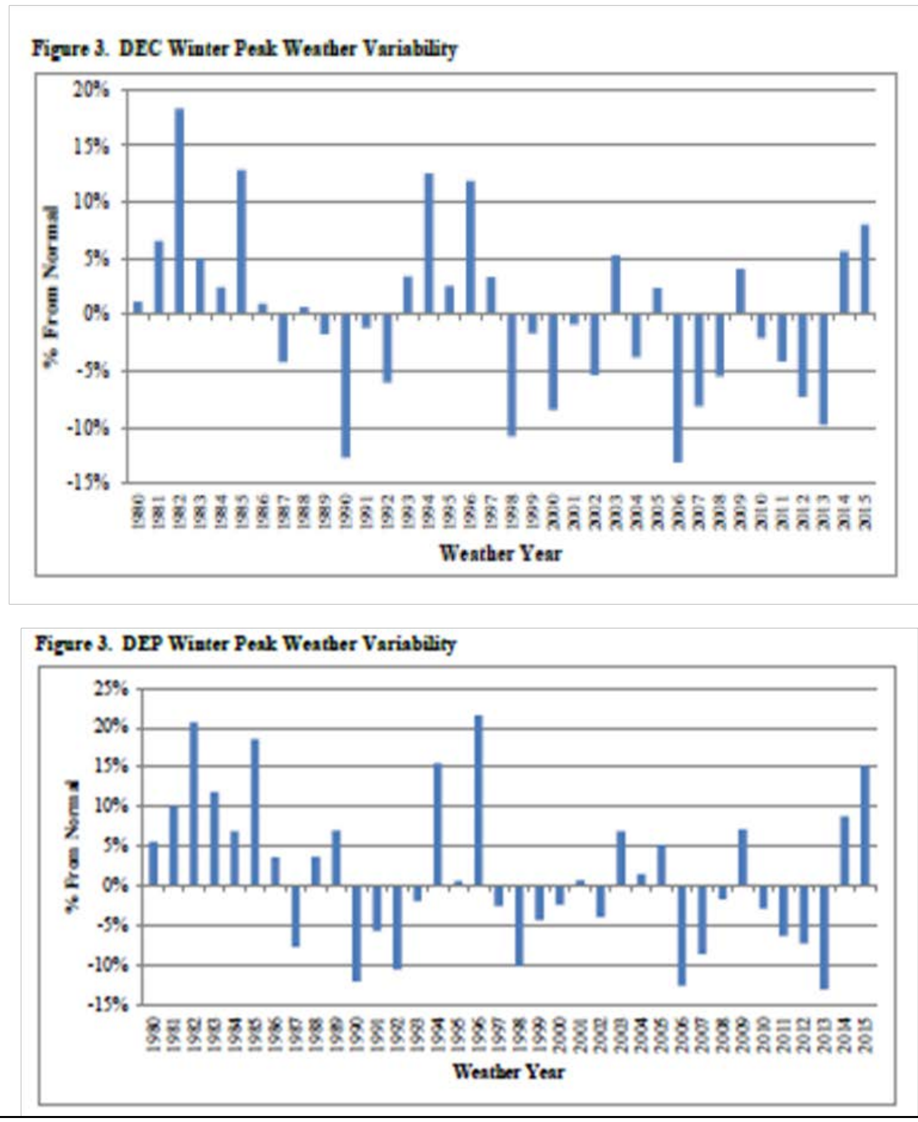
[9] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

Figure JFW-3: Figure 3 from the DEC and DEP RA Studies



that the highest loads modeled in the 2016 RA Studies correspond to two instances in the 1980s and two in the 1990s; the 2014 and 2015 events are moderate in comparison.

30. Through discovery, the Companies provided data showing the scenarios (weather year, day, hour, load forecast error assumption), that led to lost load in the 2016 RA Studies.[10] For DEP, using all years, the RA Study has 86% of the expected load loss hours in winter; if only weather data 1997 and later is used, 75% of the load loss hours

[10] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

are in summer and only 25% are in winter. For DEC, 69% of the expected load loss hours are in winter in the RA Study; but if only weather since 1997 is modeled, 92% of the load loss hours are in summer, 8% are in winter. This data shows that in the RA Studies, the vast majority of the hours with load loss result from scenarios based on those instances of extreme cold from the 1980s and 1990s, and the overstated loads associated with them due to the flawed regressions. While including more rather than less historical weather data is preferred, excluding the 1982-1996 data quantifies how the flawed regressions have skewed the results and overstated winter resource adequacy risk. The data strongly suggest that if the regressions were corrected, the resource adequacy risk would still be weighted toward summer on both systems.

31. Thus, the vast majority of the winter LOLE in the 2016 RA Studies is based on a highly simplified and inaccurate assumption about how loads would increase due to extreme temperatures, applied to temperatures that have not been seen in decades. These assumptions, which were new in the 2016 RA Studies, drove the winter risk and reserve margins very high.

32. The inaccuracy of the extrapolation equations used in the 2016 RA Studies was raised in the Wilson 2017 RM Report, but neither the Joint Report nor the December 2017 Presentation substantively addressed this issue.[11] The additional three years of data included in the updated data set provide further support for the conclusion that the extrapolation greatly overstated loads under the most extreme temperatures.

33. The regressions used in the 2016 RA Studies are also flawed in that they did not consider wind speeds, which also have a substantial impact on loads. Figures JFW-1 and JFW-2 suggest that the relationship between temperature and load is not that strong; for example, Figure JFW-1 shows that temperatures in the low 20s have resulted in loads around 14,300 MW, but on other days such temperatures have resulted in loads about 2,000 MW higher. One approach to reflecting the impact of wind speeds is to calculate a "wind chill" measure that combines temperature and wind into a single

[11] Response to Data Request SACE/NRDC/Sierra Club 1-23(a) (stating that slides in the December 2017 Presentation are the only response to the Wilson 2017 RM Report's critique of the regressions).

parameter. For example, the regional transmission organization PJM Interconnection, L.L.C. ("PJM") utilizes a "Winter Weather Parameter" in its winter load forecasting. The equation for the Winter Weather Parameter suggests that for winds in excess of 10 MPH, each 10 MPH of wind speed is equivalent to 5 additional degrees of cold.[12]

34. While not addressing the inaccuracy of the regressions, the Joint Report did provide information showing the substantial impact of even small changes to the regressions on the 2016 RA Study results. As a sensitivity case for DEC, the impact of colder temperature on load was reduced by 50% for the very few instances of temperatures below 6 degrees (7 days during 1982 to 1996; none have occurred since). This was estimated to reduce the reserve margin by 0.33%.[13] That's a substantial impact on the reserve margin and winter resource adequacy risk; but this sensitivity analysis falls far short of addressing the inaccuracy of the regressions. As the trend lines in Figure JFW-1 show (comparing the green to the red line), the DEC RA Study overstates loads by about 500 MW at 6 degrees, increasing to about 1,500 MW at the lowest temperatures. This sensitivity case used the flawed regression equation for loads at 6 degrees and higher temperatures, and made small changes for temperatures in the 4 to 6 degree range. The adjustment in the sensitivity case exceeded 100 MW for only four days, and exceeded 400 MW on only one day.[14] Yet this minor adjustment was estimated to have a 0.33% impact on the reserve margin. More completely correcting the regressions (for example, by using the red trend lines shown in Figures JFW-1 and JFW-2 for temperatures below about 11 degrees) would have a much larger impact on the reserve margin, and would also substantially reduce winter resource adequacy risk.

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[12] PJM Manual 19 *Load Forecasting and Analysis* rev. 33, October 25, 2018, pp. 13-14, available at https://www.pjm.com/-/media/documents/manuals/m19.ashx.

[13] Response to Data Request SACE/NRDC/Sierra Club 4-11, attachment slide 7.

[14] Response to Data Request SACE/NRDC/Sierra Club 4-11, attachment slide 3.

B. Representing Economic Load Forecast Error

35. If peaks loads grow faster than forecasted (for example, due to stronger than expected economic growth), it could result in actual reserve margins lower than were anticipated in resource plans published years in advance. The 2016 RA Studies include "economic load forecast error," intended to represent the possible error in four-year-ahead load forecasts (DEC RA Study, p. 16). This resulted in modeling scenarios under which the peak was under-forecast by 4%, with no supply-side adjustments. This assumption had a substantial impact on the reserve margins: if the analysis instead uses the lower error reflected in one-year ahead load forecasts, the reserve margin declines by about 1%.[15]

36. The Wilson 2017 RM Report criticized the representation of economic load forecast uncertainty on two grounds. First, it explained why it was not appropriate to include *multi-year* economic load forecast uncertainty in the 2016 RA Studies, because the model used was unable to represent the short-lead-time actions that the Companies and market participants would take if stronger-than-expected load growth were to materialize and continue year after year. Second, the Wilson 2017 RM Report explained that the probability distribution of economic load forecast error used in the 2016 RA Studies was not supported by the underlying data it was based upon, and greatly overstated the risk of large unexpected increases in peak load.

37. The Public Staff criticized the same two aspects of the representation of load forecast uncertainty (multi-year, and probabilities assigned to large under-forecast).[16] In the Joint Report, the Public Staff stated (p. 10) that it believes the approach to load forecast uncertainty used in the 2016 RA Studies is "problematic and will likely result in an incorrect calculation." In its comments in the Joint Report, the Companies evaluated and criticized the Public Staff's specific proposal for representing load forecast

[15] December 2017 Presentation, slide 27.

[16] Joint Report pp. 9-11.

uncertainty. Rejecting the Public Staff's proposal, and failing to address my criticisms, the Companies then supported the assumptions used in the 2016 RA Studies.[17]

38. The December 2017 Presentation rationalized using multi-year economic load forecast uncertainty as follows: "Given that it takes 3-5 years to put new generation infrastructure in place, the Companies and Astrapé believe that 3 years of economic load growth uncertainty is appropriate."[18] However, as explained in the Wilson 2017 RM Report, this ignores the fact that there are many short lead time actions that can and very likely would be taken. If load grows faster than expected, the utilities (and customers and other market participants too) would have time to adjust their plans, if the rate of load growth raised concern about resource adequacy. To name a few potential actions, the development of some new resources might be accelerated; demand response or energy efficiency programs could be increased; a planned retirement could be delayed; firm purchases from adjacent regions could be adjusted; or wholesale sales contracts could be allowed to expire.

39. The 2016 RA Studies essentially assume the reserve margin and resource plan must be chosen over three years in advance, and then the resource plan must remain frozen, even if load growth is much stronger than expected year after year.[19] This is not realistic, and is at odds with the Companies' business practices, including the biannual IRP planning cycle. The assumption that load can rise sharply and unexpectedly, but no adjustments to the resource mix can or would be made over three years, biases the planning reserve margin upward.

40. It is notable that PJM, in its resource adequacy analyses, acknowledges that resource plans can and would be adjusted as needed if load grows faster than expected. Accordingly, while PJM's resource adequacy analysis focuses on determining

[17] Joint Report pp. 21-24; December 2017 Presentation, slides 21-27.

[18] See also response to Data Request SACE/NRDC/Sierra Club 4-10.

[19] This was confirmed in the responses to Data Requests SACE 2-22 and 2-23 in Docket No. E-100 Sub 147.

planning reserve margins for peaks over three years into the future, PJM represents only one year of economic load forecast error in its analyses.[20]

41. The Wilson 2017 RM Report also noted that it could be appropriate to represent multiple years of forecast uncertainty in a more sophisticated model that is able to internally determine supply-side or demand-side adjustments over time as the load forecast and other resources change over time. For instance, the Electric Power Research Institute's Over/Under capacity planning model, developed in the 1970s, had this capability.[21] Planning reserve margins for future years are somewhat smaller if it is recognized that supply plans can be adjusted over time. However, the SERVM model that was used in the 2016 RA Studies does not have the capability to represent any such contingent decisions. To represent multi-year load forecast uncertainty, but not the actions that would be taken to adapt resource planning over time as such uncertainty resolves, is a flawed methodology that biases the result toward higher planning reserve margins. I again conclude that it was inappropriate to use 3-year load forecast uncertainty; it would be more appropriate to use one year (which, as noted, would lower the reserve margin by 1%, even if no other changes were made).

42. Turning to the values used for the economic load forecast error, the economic load forecast uncertainty was represented as a symmetric probability distribution (DEC RA Study Table 4 p. 17). A 7.9% probability was assigned to both +4% and -4% shifts in load, 24% probability was assigned to both +2% and -2% shifts, and 36.3% chance was assigned to no change due to economic load forecast error. Thus, all loads, including the extreme weather-related load levels discussed in the prior section of this report, are increased by an additional 4% under the highest economic load forecast error scenario, and 2% under an additional scenario assigned a 24% probability.

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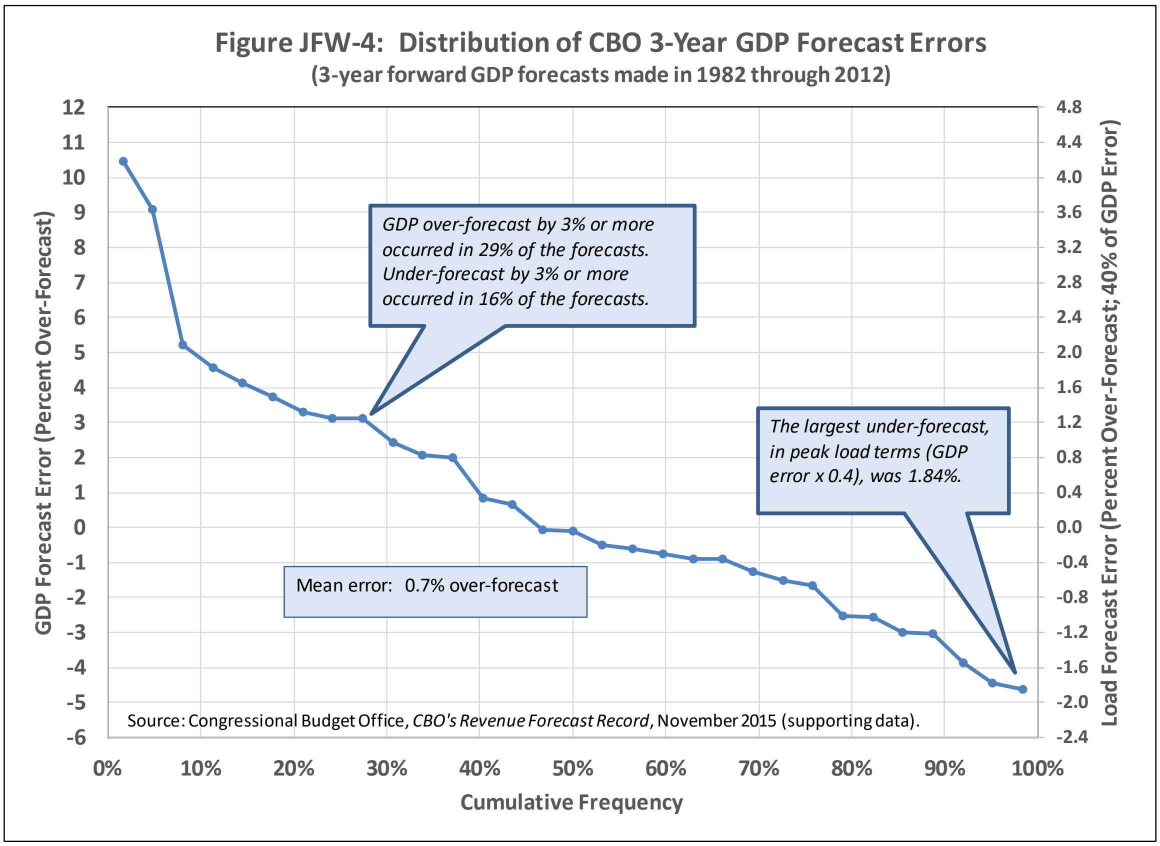
[20] See, for instance, PJM, *2012 PJM Reserve Requirements Study,* p. 20 (explaining the rationale for using a forecast error factor representing one year of forecast error).

[21] Decision Focus Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning*, EPRI EA-927, Project 1107, October 1978.

43. The DEC RA Study states (pp. 16-17) that the probability distribution was based on the historical forecasting errors reflected in the U.S. Congressional Budget Office ("CBO") U.S. Gross Domestic Product ("GDP") forecasts, and applying a 0.4 elasticity of peak demand to economic changes.[22] The CBO data is readily available, including the CBO's own analysis of its 3-year GDP forecasting errors.[23] Figure JFW-4 presents the full distribution of the 3-year forward GDP forecast errors (left axis), and the corresponding load forecast errors based on the 2016 RA Studies' 0.4 elasticity assumption (right axis).



[22] It is also questionable whether CBO U.S. GDP forecasting errors are a reasonable proxy for the applicable economic forecasting errors for the North Carolina economy. The DEC and DEP load forecasts rely upon forecasts of the North Carolina economy.

[23] Congressional Budget Office, CBO's Revenue Forecasting Record, November 10, 2015, and Supplemental Data available at https://www.cbo.gov/sites/default/files/114th-congress-2015-2016/reports/50831-RevenueForecasting-SuppData.xlsx. In the response to data request SACE/NRDC/Sierra Club 4-12, Duke provided its own analysis of GDP forecast errors, however, Duke's GDP data are different from the CBO's, and its analysis is also different. No citation was provided for the source of the data Duke used for this analysis.

44. The symmetric load forecast error distribution used in the 2016 RA Studies misrepresents the distribution of CBO forecast errors and associated load forecast errors. The CBO forecast errors are not symmetric, and the under-forecast errors tend to be small. This is not surprising: economic downturns can be sudden, largely unexpected, and sharp, as seen in 2008. Surprisingly strong economic growth, by contrast, would tend to develop and accumulate more slowly over time.

45. The 2016 RA Studies assign almost 32% probability to under-forecast errors whose magnitude (+4% or +2%, in load forecast terms) never occurred even once in 30 years, according to the CBO data the distribution was purportedly based upon. Over the thirty years of CBO data, the largest 3-year GDP under-forecast error was 4.61 percent, which translates (times 0.4) into a load forecast under-forecast of only 1.84%. In contrast, the 2016 RA Studies assign 7.9% and 24% probability to under-forecasting peak load by 4 percent and 2 percent, respectively, as described above. The economic load forecast error distribution used in the 2016 RA Studies misrepresents the CBO data, and greatly overstates the risk of substantial under-forecasting.

46. It is also notable that economic forecasters now expect lower U.S. GDP growth than occurred over the past thirty years, which further shrinks the likelihood of large under-forecasting errors. According to the Federal Reserve Bank of Philadelphia's biannual Livingston Survey of approximately 25 economic forecasters, up until 2006, forecasters expected 3.2 percent per year GDP growth, but more recently the median expectation has been only 2.2 percent per year.[24]

47. It also notable that the Companies have not performed any research that supports the assumed elasticity value of 0.4.[25]

48. The exaggerated representation of load forecast error (inappropriately using multi-year error, and misrepresenting the underlying CBO data) had a substantial impact on the 2016 RA Studies. Of the scenarios with load loss in the RA Study simulations

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[24] Federal Reserve Bank of Philadelphia, *Livingston Survey*, December 2018; releases from 1991 to present are available at https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey.

[25] Response to Data Request SACE/NRDC/Sierra Club 4-9c.

for DEC, 62% occurred under the +4% load forecast error scenario, and 83% occurred under the +2% and +4% scenarios.[26] For DEP, 51% of the load loss instances were under the +4% scenario, 77% under the +4% and +2% scenarios.

49. Consequently, even accepting the inclusion of multi-year economic forecast errors, and accepting use of the CBO data to develop the distribution, the 2016 2016 RA Studies have misrepresented the distribution of errors, exaggerating the risk of substantial under-forecasting. This exaggeration of the potential for under-forecasting of economic load growth, in addition to the exaggeration of winter peak loads, will further bias the planning reserve margin upward.

C. Demand Response Assumptions

50. Historically, the Companies were summer-peaking, with loss of load risk, and therefore capacity value, concentrated in the summer period.[27] The Companies therefore have designed their demand response programs to reduce demand on the hottest summer days of the year,[28] and, as a result, have had roughly twice as much demand response available in summer as in winter. The 2016 RA Studies assume that demand response will continue to be summer-focused, despite now identifying more resource adequacy risk in winter than in summer. Under more balanced demand response assumptions, the seasonal resource adequacy risk would also be more balanced.

51. The DEC RA Study assumed 1,119 MW of summer demand response and 514 MW of winter demand response. (p. 25) If instead the winter demand response is brought up to the summer level (and everything else remains the same), this eliminates load loss in the winter in the 2016 RA Study to the point where there are now more summer than winter hours with load loss.[29] The DEP RA Study assumes almost twice as

[26] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

[27] See, for instance, *Duke Energy Carolinas 2012 Generation Reserve Margin Study*, p. 14; response to Data Request SACE/NRDC/Sierra Club 4-1c.

[28] Response to Data Requests NCSEA 3-36, 3-37.

[29] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

much demand response in summer than in winter -- 926 MW to 496 MW. (p. 25) But if winter demand response is expanded by 900 MW (which, if DEP believes risk is mainly in the winter, it should definitely pursue), most of the hours with load loss would be in the summer.

52. This shows that the conclusion that the risk of load loss is concentrated in the winter is not only greatly exaggerated due to the flaws discussed earlier in this report, it is also highly sensitive to particular resource mix assumptions, such as demand response, that can and should be adjusted for the future. The Companies' 2016 analysis shows that the technical and economic potential for residential winter demand response exceeds 2,300 MW for both DEC and DEP.[30] Yet the Companies are not considering any changes to their demand response programs at this time.[31]

D. OPERATING RESERVE AND LOAD FOLLOWING ASSUMPTIONS

53. The 2016 RA Studies also exaggerate winter risk through the operating reserve assumptions. The model used in the DEC RA Study (p. 25) sets aside 716 MW for operating reserve and regulation, plus 1.5% of load (approximately 300 MW) for load following, in all hours, for a total of over 1,000 MW (for DEP, the corresponding number is about 750 MW).

54. For both DEC and DEP, about 60% of the annual load loss hours in the 2016 RA Studies occur on the brief (and, as explained above, overstated) load spikes on very cold winter mornings, with the majority of these outages lasting one or two hours.[32] During these very brief winter morning load spikes, the system operators know that loads will soon decline and that such a substantial amount of reserve is not needed at that time. Accordingly, the system operators would very likely choose to go somewhat short on these reserves rather than call for firm load curtailment. The modeling assumption that

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[30] Response to Data Request SACE/NRDC/Sierra Club 4-16 attachment, *Duke Energy North Carolina DSM Market Potential Study,* prepared by Nexant for Duke Energy, December 19, 2016, pp. 47, 50, 62, 71.

[31] Response to Data Requests NCSEA 3-38, 3-39.

[32] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

this large amount of resource would be held, causing firm load curtailment, further exaggerates the risk of load loss on winter mornings in the 2016 RA Studies. By contrast, the summer peaks typically occur over multiple hours with load levels changing relatively slowly, so the adopted operating reserve assumptions are more justified for the summer period.

55. In the DEC RA Study, if it is assumed that the system operators would allow the over 1,000 MW set aside as operating reserve and load following to briefly fall by 500 MW during the brief winter morning load spikes, the instances of winter load loss would be fewer than in summer.[33]

E. MODEL ESTIMATES OF SEASONAL AND HOURLY CAPACITY VALUE ARE HIGHLY SENSITIVE TO ASSUMPTIONS THAT MAY CHANGE

56. The estimates of the particular seasons, months, and hours where the risk of load loss is highest, based on the modeling approach documented in the 2016 RA Studies and similar Capacity Value Study, will be highly sensitive to various model assumptions that can change over time. Assumptions about the penetration of seasonal resources such as wind, solar and demand response can shift the seasonal balance, and also shift the particular hours in which capacity is likely to be scarce. Tailored demand response programs, or energy storage capacity (such as storage associated with solar resources) can shave peaks or shift them to adjacent hours. Load shapes may also change, due to the penetration of new end-use technologies, or changes in customers' habits, such as usage of programmable thermostats. Various scenarios of these assumptions might suggest very different seasonal and hourly patterns for the modeled load loss.

57. The Companies' methodology is to identify certain seasons, months, and hours, and assign capacity value to those time periods, based on such model runs.[34] The winter/summer weights, mentioned earlier, are highly weighted toward winter, which, as

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[33] Response to Data Request SACE/NRDC/Sierra Club 1-26.

[34] The details are in a confidential response to Data Request NC Public Staff 6-2 in Docket No. E-100, Sub 158.

explained above, is based on flawed analysis. Correcting those flaws would shift resource adequacy risk back toward summer, as would higher penetration of winter demand response or wind resources, which tend to have higher output during winter peaks than summer peaks.

58. A more balanced seasonal weighting is also suggested by the simple fact that the vast majority of high load hours are in summer on both systems. According to DEC's load forecast, 83% of the highest load hours (top 1%) are in summer; for DEP's load forecast, 74% of the top 1% load hours are in summer. [35]

59. DEC's proposed Schedule PP proposes summer capacity credit only in the months of July and August from 4 to 8 PM. Both companies propose winter capacity credit for six hours per day, 6 to 9 AM and 6 to 9 PM. DEC's proposed Schedule PP sets a capacity credit more than three times higher for winter mornings than for winter evenings; DEP's winter morning rate is more than twice the winter evening rate. But the modeling that determined these particular schedules as well as the high ratios is also highly sensitive to various assumptions about load shapes, customer habits, and demand response.

V. SUMMARY AND RECOMMENDATIONS

60. This evaluation leads to the conclusion that the recommended increases in the DEC and DEP reserve margins compared to pre-2016 levels are not supported by the 2016 RA Studies and are not necessary at this time. This evaluation also leads to the conclusion that the 2016 RA Studies have greatly overstated winter resource adequacy risk relative to summer risk, so the winter/summer capacity values of solar resources proposed for use in the 2018 IRPs (Tables 9-B and 9-C, pp. 45-46), as well as the avoided capacity cost weightings (100%/0%, 90%/10%) proposed for use in the Companies' Schedule PP filed in Docket No. E-100, Sub 158, should be rejected, and much more balanced seasonal weights approved.

[35] Response to Data Request SACE/NRDC/Sierra Club 1-21 attachment. These values are based on the forecasts for 2023.

61. The following flaws in the 2016 RA Studies, and associated Solar Capacity Value study, inflate both the winter resource adequacy risk and planning reserve margins, and consequently understate the capacity value of solar resources:

a. The regressions used to estimate the impact of extreme cold on load levels substantially overstate the impact; more accurate regressions more focused on colder temperatures suggest a much more moderate impact of extreme cold on load.
b. The assumption that roughly half as much demand response is available in winter as in summer.
c. The assumption that large amounts of capacity would be held aside for operating reserve and load following, and firm load curtailed, during the rare and very brief load spikes that occur on very cold winter mornings.

62. The flawed economic load forecast uncertainty assumption further inflates the recommended reserve margin:

a. The application of multiple years of economic load forecast uncertainty is inappropriate in a model that does not represent the contingent actions that could be taken if load grows more rapidly than expected.
b. Even accepting the application of multiple years of economic load forecast uncertainty, the probability distribution used, based on CBO data, misrepresents that data, and assigns substantial weight to outcomes that have never occurred in the underlying data.

63. The Companies' approach to estimating seasonal, monthly, and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins, reflected in the 2016 RA Studies and similar Capacity Value Study, will be highly sensitive to various assumptions that can change dramatically in just a few years' time, such as load shapes during summer and winter peak periods, demand response, and penetration of seasonal resources such as wind and solar. This suggests that a fixed rate design, such as reflected in Schedule PP, should not be overly focused on specific months of the year or hours of the day, because the Companies' estimates of the

seasons and hours with resource adequacy risk can change over time as load shapes and the resource mix change. Additionally, the price signals inherent in the rate design can shifts capacity needs to adjacent hours or months. While it is important to strive for accurate price signals, it is also important to strive for price signals that are reasonably stable over time, and likely to remain reasonably accurate as conditions change. Because the Companies' proposed Schedule PP rate designs are based on the same flawed analysis that is highly sensitive to assumptions, I also recommend rejecting the proposed monthly and hourly rate structures.

64. I do not recommend specific seasonal weightings, monthly and hourly rate structures, or reserve margins, as this would require use of the Companies' modeling tools to perform further analysis with the flaws identified above corrected.

65. Finally, this evaluation leads to the following suggestions for future IRPs and supporting resource adequacy studies:

a. The Companies should study the relationship between extreme cold conditions and load, taking into account other relevant factors such as likely facility closures and the impact of wind speeds, to inform future resource adequacy studies.
b. The Companies should further research the drivers of sharp winter load spikes under extreme cold conditions, and develop programs for shaving these rare and brief spikes.
c. The Companies should research the potential for load forecast errors due to economic and demographic forecast errors, and the realistic extent to which this could ultimately lead to less capacity than planned in a delivery year, also to inform future resource adequacy studies. Resource adequacy studies must be internally consistent in their assumptions in this regard – if the potential for adjustments to the resource mix in a one- or two-year ahead time frame are not modeled, only one year of economic load forecast uncertainty should be modeled.

d. The Companies should provide much more scenario analysis and sensitivity analysis of its studies for determining reserve margins and seasonal, monthly, and hourly capacity values. The sensitivity of the recommendations to key assumptions should be explored and documented. For example, as shown above, the 2016 RA Studies results are very sensitive to the choice of 20 or 30 historical weather years, to the details of how extreme cold is assumed to affect load, and to demand response assumptions; such sensitivities should be explored and documented with any such study. The sensitivity of the recommendations to various assumptions that can change over time, including assumptions that could change due to price signals or utility programs, should also be provided.

e. More detailed information about future resource adequacy and related studies should be required. To start, all model reports, and a more comprehensive set of sensitivity analyses, should be provided.

APPENDIX A: LACK OF INFORMATION LIMITING THIS REVIEW

1. Resource adequacy studies necessarily involve numerous assumptions about loads and resources. To fully evaluate such a study requires a careful review of the various assumptions and how they interact through the simulation to create the study results. Of critical importance is the probabilistic representation of loads and resources. Because the approach involves finding the reserve margin to satisfy LOLE = 0.1 (one outage event in ten years), the loss of load will occur only under extremely low-probability combinations of load and resource conditions. Therefore, to validate such a simulation (to gain confidence that the various assumptions are realistic, individually and in combination, and combine to produce realistic results) requires careful review of, among other things, the combinations of multiple rare events that lead to the loss of load. More specifically, it is necessary to examine when the loss of load occurs (what seasons, weather conditions, hour of the day), the load levels when load loss occurs (combining economic and weather uncertainty assumptions), the availability of all generation resources when load loss occurs, the reasons for lack of availability (including purchases, demand response, and energy-limited resources such as pumped hydro).

2. A thorough review should also consider the results of additional sensitivity analyses around various assumptions, to understand the impact of the assumptions on the results and recommendations. Sensitivity analysis will often reveal that the results are unexpectedly sensitive to certain assumptions. This may suggest flaws in the model logic, and/or a need to more carefully consider the particular values chosen for the assumptions.

3. While more details were provided in this proceeding than were available for the Wilson 2017 RM Report, much requested information was refused, including the following:

a. The standard SERVM model reports (“Default Reports”, “Debug Reports”, “Input Validation Information”) for the 17% and 16% winter reserve margin cases.[36]
b. Additional details about the scenarios under which load loss occurs.[37]
c. The load loss details under the base case that supports the recommended 17% winter reserve margin.[38]
d. The load loss details under the alternative case with a 16% winter reserve margin.[39]
e. The load loss details under the four solar penetration cases evaluated in the Solar Capacity Value Study.[40]
f. Hydro and pumped hydro production by hour in the simulations.[41]
g. Additional sensitivity analyses requested pertaining to economic load forecast uncertainty, demand response, and neighbor assistance.[42]

4. Some of these requests were refused, stating that the report was not generated when the model runs were performed, or the information was not saved. However, it is not burdensome to turn on additional reports and re-run a model. The refusal to provide the information reflects an unwillingness to allow the full details of the simulations to come under scrutiny. This lack of information hampered the evaluation of the 2016 RA Studies discussed in this report.

[36] Response to Data Request SACE/NRDC/Sierra Club 4-7.

[37] Response to Data Request SACE/NRDC/Sierra Club 4-2.

[38] Response to Data Request SACE/NRDC/Sierra Club 4-4a.

[39] Response to Data Request SACE/NRDC/Sierra Club 4-4b.

[40] Response to Data Request SACE/NRDC/Sierra Club 4-4c.

[41] Response to Data Requests NCSEA 3-49, 3-50, 3-51.

[42] Response to Data Request SACE/NRDC/Sierra Club 4-13.

APPENDIX B: QUALIFICATIONS OF JAMES F. WILSON

James F. Wilson is an economist and independent consultant doing business as Wilson Energy Economics, with a business address of 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814. Mr. Wilson has 35 years of consulting experience, primarily in the electric power and natural gas industries. Many of his consulting assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. His experience and qualifications are further detailed in his CV, available at www.wilsonenec.com.

Exhibit C

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

1-17 Please confirm that the Companies' proposed rate designs for (i) avoided energy rates and (ii) avoided capacity rates in this proceeding (*See*, Testimony of Glen A. Snider, pp. 26-30) are identical to the proposed rate designs for avoided energy and capacity rates that the Companies have proposed in their April 18, 2019 *Stipulation of Partial Settlement* with the Public Staff in NCUC Docket E-100 Sub 158.

a. If the proposed avoided energy and/or avoided capacity rate designs in this proceeding are different than the proposed rate designs in E-100 Sub 158, please provide a narrative description of these differences and any supporting documents that the Companies used or relied upon to develop its proposed avoided energy and avoided capacity rate designs in this proceeding.

Response:

For the proposed SC specific avoided energy and capacity rates, the Companies utilized rate designs identical to the rate designs proposed in the Companies' April 18, 2019 Stipulation of Partial Settlement with the Public Staff in NCUC Docket E-100 Sub 158.
The actual rates proposed in SC differ to those proposed in NC due to updated inputs.

Exhibit D

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study

8/27/2018

PREPARED FOR

Duke Energy

PREPARED BY

Kevin Carden
Nick Wintermantel
Alex Krasny
Astrapé Consulting

Contents

I. Solar Capacity Value Study Summary

As Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) continue to add solar to their systems, understanding the reliability contribution of solar resources is critical for generation planning and projecting capacity needs as part of its Integration Resource Plan (IRP). Conventional thermal resources are typically counted as 100% of net capability in reserve margin calculations for future generation planning since these resources are fully dispatchable resources when not on forced outage or planned maintenance. Due to the intermittent nature of solar resources, it is not reasonable to assume that these resources provide the same capacity value as a fully dispatchable resource. Peak loads for DEC and DEP in the winter occur in the early morning and late evening when the solar output is low, while peak loads in the summer occur across the afternoon and early evening which is more coincident with solar output. Solar output shapes and the timing of peak demand periods must be considered to determine the capacity value or reliability contribution of a solar resource compared to a fully dispatchable resource such as a combustion turbine (CT).

Astrapé performed this capacity value study using the Strategic Energy Risk Valuation Model (SERVM) which was the same model utilized for the 2016 Resource Adequacy Studies. The inputs of the model are documented in the body of this report. Extensive work went into the development of fixed-tilt and single-axis-tracking solar profiles across a 13-location grid in North Carolina and South Carolina as laid out in the body of the report.

Astrapé calculated the incremental capacity value of solar across five solar penetration levels for each company. These results can be fit to a curve to estimate the capacity value of each MW of solar added to the system. The table below shows the different penetration levels of renewable solar generation. These levels are consistent with the Companies' estimates of penetration at the time of this analysis. Consistent with NC House Bill 589, solar additions were divided up into the categories of

Existing plus Transition and then an additional four tranches of solar that are expected over the next few years. However, note that the tranches discussed in this study reflect the Companies' total expected solar procurement which includes all utility scale requirements under NC HB 589 (CPRE, large customer programs and community solar). While the exact timing and amounts of transition and incremental solar additions may change over time, it is reasonable to assume the levels provided in the table below given the current procurement targets of the companies.

Table S1. Simulated Solar Penetration Levels

	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
0 MW Level	-	-	-	-
Existing Plus Transition MW	840	840	2,950	2,950
Tranche 1	680	1,520	160	3,110
Tranche 2	780	2,300	180	3,290
Tranche 3	780	3,080	160	3,450
Tranche 4	420	3,500	135	3,585

The Existing Plus Transition capacity level was made up of mostly fixed-tilt solar with a small amount of single-axis-tracking solar. Existing behind the meter solar was modeled as a reduction in load. Table S2 provides the details for the existing plus transition capacity.

Table S2. Existing Plus Transition Capacity Breakdown

	DEC MW	DEP MW
Existing	679	1,923
Transition	161	1,027
Existing Plus Transition	840	2,950

Type	Technology	Inverter Loading Ratio	DEC MW	DEP MW
Existing: Utility Owned	Fixed-tilt	1.4	130	154
Existing: Standard PURPA	Fixed-tilt	1.3	549	1,769
Transition	Fixed-tilt	1.43	121	770
Transition	Single-Axis-Tracking	1.3	40	257
Total Existing Plus Transition			840	2,950

Tranches 1-4 solar resources were assumed to have a 1.4 inverter loading ratio with 75% being fixed-tilt and 25% being single-axis-tracking. The following table shows the capacity levels included within each tranche.

Table S3. Tranches 1 - 4 Capacity

Tranche	Technology	Inverter Loading Ratio	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
Tranche 1	75% fixed/25% Tracking	1.4	680	680	160	160
Tranche 2	75% fixed/25% Tracking	1.4	780	1,460	180	340
Tranche 3	75% fixed/25% Tracking	1.4	780	2,240	160	500
Tranche 4	75% fixed/25% Tracking	1.4	420	2,660	135	635

In order to calculate the capacity value of the solar resources, the DEC and DEP systems are simulated at the different solar penetration levels to identify projected firm load shed events. A firm load shed event occurs in an hour when DEC or DEP are short resources even after calling all demand response resources and fully utilizing assistance from external neighbors. Consistent with the reserve margin study, a Loss of Load Expectation (LOLE) for each Company is calculated and reserves are adjusted to target approximately 0.1 events per year. This is also referred to as the 1 day in 10-year standard.

LOLE by Season and Its Impact on Capacity Value

The LOLE may occur in the winter or the summer but as was seen in the 2016 Resource Adequacy Studies, winter LOLE is significantly higher than summer LOLE within both Companies due to increasing penetrations of solar capacity and the impact of cold weather uncertainty on load.

Table S4 shows the seasonal LOLE by Company for the different penetration levels. As solar is added to the system, a higher percentage of the LOLE will occur in the winter because the output of solar in the summer during peak load hours, which occur in the afternoon and early evening, is naturally higher than the output during the winter peak load hours which occur early in the morning or late in the evening. In other words, when 1 MW of nameplate solar is added to the system, the 1 MW of solar reduces summer LOLE more than it reduces winter LOLE, thereby further shifting the seasonal weighting of LOLE to the winter. This is apparent by examining the LOLE results in the table. For example, the no-solar scenario for DEC shows a seasonal LOLE weighting of 59% summer and 41% winter. However, after adding the existing and transition solar, the seasonal weighting makes a dramatic shift to 69% winter and 31% summer. After Tranche 4 solar is added, the winter weighting increases to 93% and summer reduces to 7%. The updated load forecast used in the solar capacity value study shows DEP's winter peak forecast to be about 650 MW higher than its summer forecast for the 2020 study year, while DEC's winter forecast is about 340 MW lower than its summer forecasted peak. Even though DEC's summer peak is projected to exceed its winter peak, the LOLE for DEC is still heavily weighted in the winter due to solar capacity contribution at the time of summer versus winter peak demands.

Table S4 shows that the DEP no-solar scenario has a seasonal LOLE weighting of approximately 85% winter and 15% summer. The greater winter LOLE weighting for the DEP no-solar scenario, compared to the DEC no-solar scenario, is primarily the result of greater winter load volatility and a higher winter versus summer load forecast for DEP. DEP also has a significantly greater level of Existing Plus Transition solar compared to DEC, pushing the seasonal winter LOLE weighting to greater than 99%. Thus, solar levels greater than Existing Plus Transition for DEP will have solar capacity values based solely on their capacity contribution in the winter.

Table S4. DEC and DEP Seasonal LOLE Percentage

	DEC Incremental Solar	DEC Cumulative Solar	DEC LOLE	DEC LOLE	DEP Incremental Solar	DEP Cumulative Solar	DEP LOLE	DEP LOLE
	MW	MW	Summer %	Winter %	MW	MW	Summer %	Winter %
0 MW Level	-	-	59%	41%	-	-	14.7%	85.3%
Existing Plus Transition MW	840	840	31%	69%	2950	2,950	0.6%	99.4%
Tranche 1	680	1,520	21%	79%	160	3,110	0.5%	99.5%
Tranche 2	780	2,300	11%	89%	180	3,290	0.4%	99.6%
Tranche 3	780	3,080	7%	93%	160	3,450	0.3%	99.7%
Tranche 4	420	3,500	7%	93%	135	3,585	0.3%	99.7%

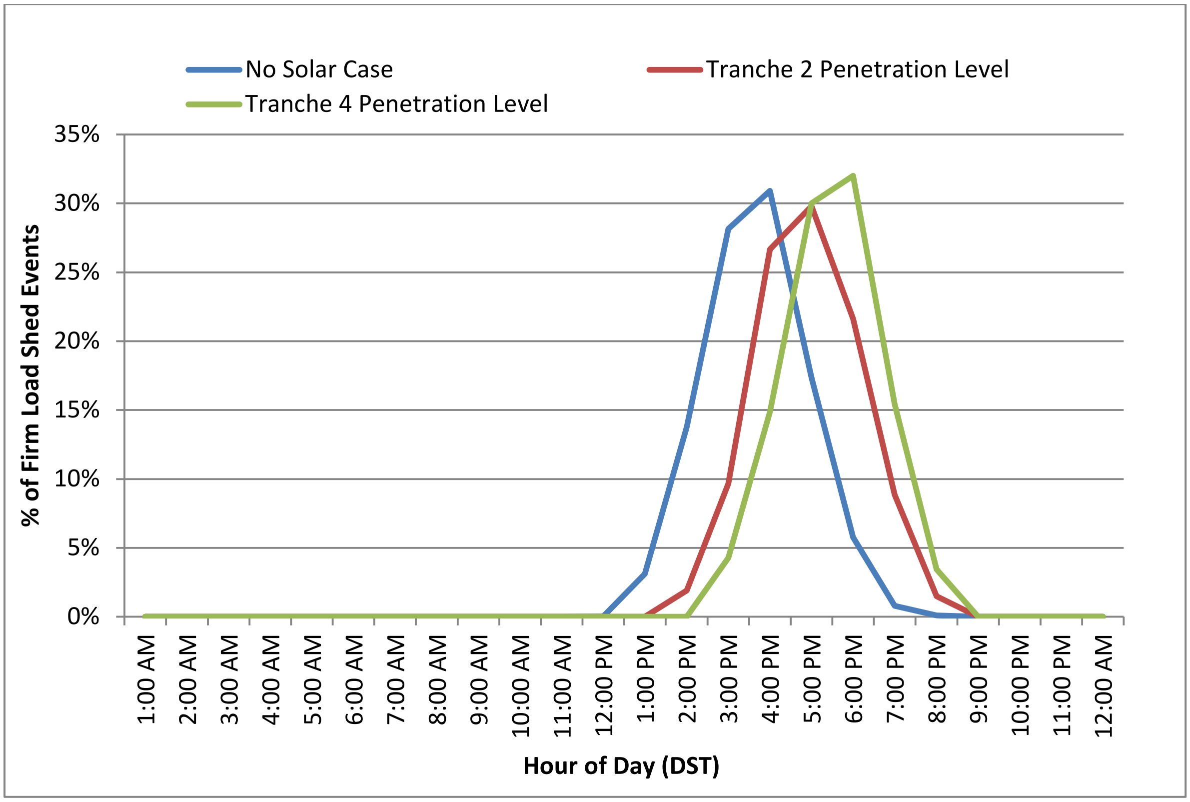
LOLE by Hour of Day and Its Impact on Capacity Value

The seasonal LOLE table alone allows for a reasonable approximation of the annual capacity value of solar resources. For example, assuming that solar receives a 50% value in the summer and a 5% value in the winter (similar to previous company estimates), then the annual capacity value for DEP at Tranche 4 could be estimated using the following formula: 5% winter capacity value * 99.7% winter LOLE weighting + 50% summer capacity value * 0.3% summer LOLE weighting = 5.1%. While this simplified approach captures the appropriate seasonal LOLE, it does not account for how the firm load shed events change across the day in each season as solar penetration grows, so the approximate calculations will not exactly match the values derived from the simulations.

To illustrate further, Figure S1 shows the percentage of firm load shed events in DEC by hour of day in the summertime for the no-solar case and two additional solar penetration levels. The percentages for each curve total to 100%. This figure demonstrates that the timing of the peak net load shifts to later in the evening across increasing solar penetration levels[1]. Before significant solar is added, both Companies are expected to experience load shed events primarily during the 1 pm - 6 pm hours in the summer with the most concentrated portion in the 3 pm to 5 pm hours as shown by the blue line. As solar capacity is added, the timing of the peak net load and therefore firm load shed hours are pushed out to later in the day when the solar output is lower. By the time Tranche 4 solar resources are included, the more concerning hours of the day in the summer are from 3- 8 pm when solar output is lower. This impact lowers the summer solar capacity value as solar penetration increases.

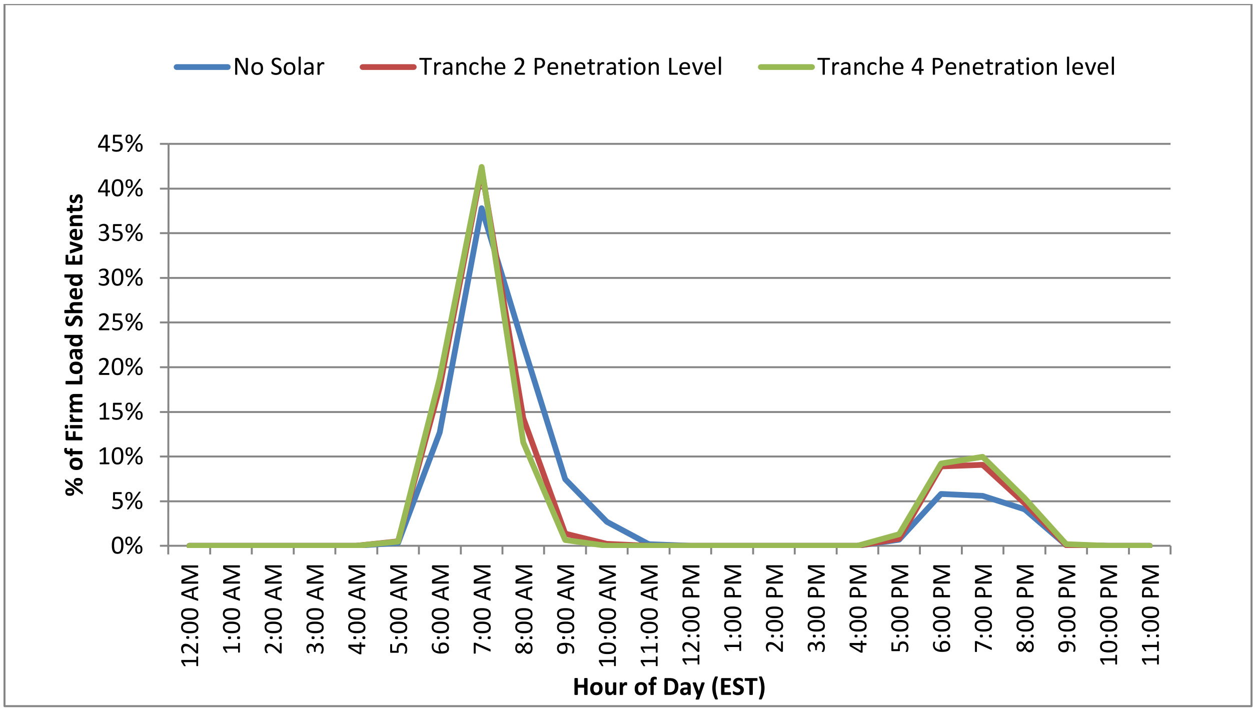
[1] Net load as discussed here reflects the gross load minus any renewable resources and represents the load that is served by the dispatchable fleet.

Figure S1. DEC % of Firm Load Shed Events by Hour of Day (Summer)



A similar pattern is seen in the winter as shown in the following figure. As solar penetration increases, the load net of solar output becomes lower in hours from 8 am to 5 pm causing more of the LOLE events to be concentrated in the 7 am hour when the solar has lower output. While small, this is the reason solar provides slightly less winter capacity value as more solar resources are brought online.

Figure S2. DEC % of Firm Load Shed Events by Hour of Day (Winter)



Solar Capacity Value Results

By modeling thousands of iterations in SERVM with 36 different weather years, both the seasonal and hourly pattern changes are captured across the different solar penetration levels. As solar increases, system LOLE shifts more heavily to the winter and the equivalent capacity value declines because the firm load shed events no longer occur during solar hours and become more prominent during hours with lower solar output.

Table S5 shows the DEC solar capacity value results. As discussed in the methodology portion of the report, SERVM simulations were performed at each solar penetration level with each level targeting a 0.1 LOLE per year. The probability-weighted output of the solar resource was then overlaid with the firm load shed event table to determine the final capacity values. The first MW of solar in DEC provides a 27% annual capacity value but after 840 MW are added, the next MW provides only an 11% equivalent annual capacity value[2]. The solar capacity values reflect the equivalent CT capacity value. A CT is given a 100% capacity credit so the first MW of DEC solar provides 27% of the capacity value that a CT provides. The fixed-tilt solar and the single-axis-tracking resources were evaluated separately with each additional tranche. The results show that at Tranche 1, fixed-tilt solar has a 6.5% annual capacity value while at Tranche 4 it is reduced to 1.2%. The capacity value for single-axis-tracking solar resources ranges from 10.9% to 2.9% across the four tranches on an annual basis.

Table S5. DEC Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEC - 0 Solar	2.5%	44.7%	27.2%
840	840	DEC - 840 Existing + Transition	0.9%	33.6%	11.1%
680	1,520	DEC - Tranche 1 - Fixed	0.5%	29.5%	6.5%
780	2,300	DEC - Tranche 2 - Fixed	0.4%	23.1%	2.9%
780	3,080	DEC - Tranche 3 - Fixed	0.2%	19.4%	1.6%
420	3,500	DEC - Tranche 4 - Fixed	0.2%	14.6%	1.2%
680	1,520	DEC - Tranche 1 - Tracking	2.0%	45.3%	10.9%
780	2,300	DEC - Tranche 2 - Tracking	1.8%	36.6%	5.6%
780	3,080	DEC - Tranche 3 - Tracking	1.3%	31.9%	3.4%
420	3,500	DEC - Tranche 4 - Tracking	1.1%	25.6%	2.9%

[2] All capacity values provided in the report represent the incremental capacity value of the next MW given the referenced solar penetration. The average capacity contribution for an entire block of solar resources can be estimated by averaging the incremental value for the first MW of the block and the incremental value for the first MW of the next block.

Figure S3 shows the results plotted as a function of solar capacity.

Figure S3. DEC Annual Capacity Value by Solar Penetration

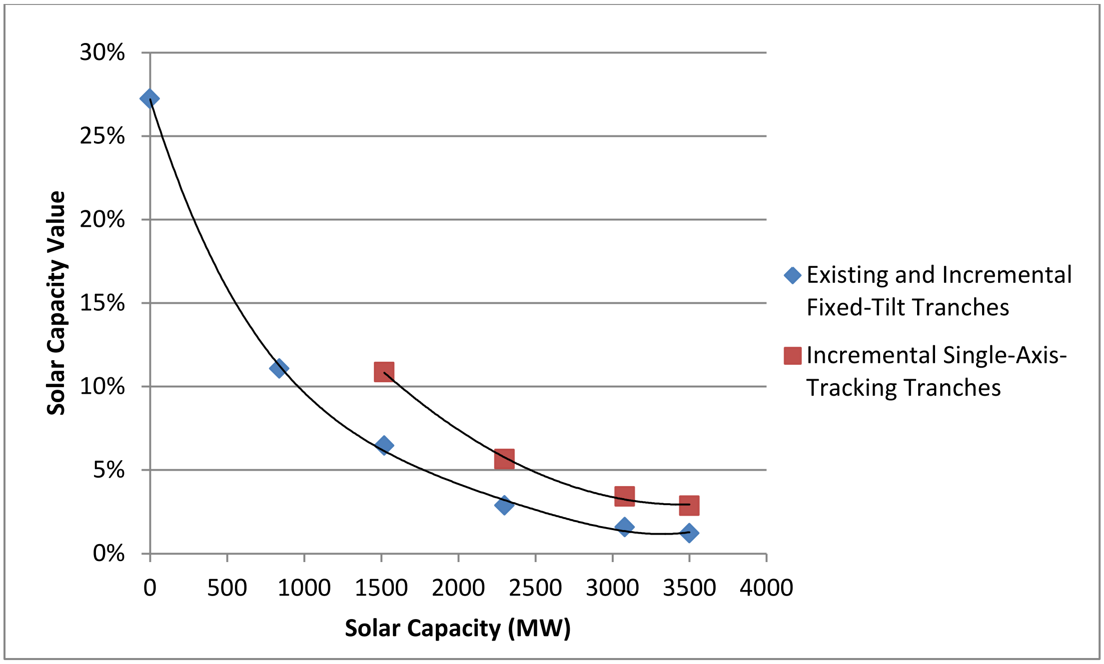


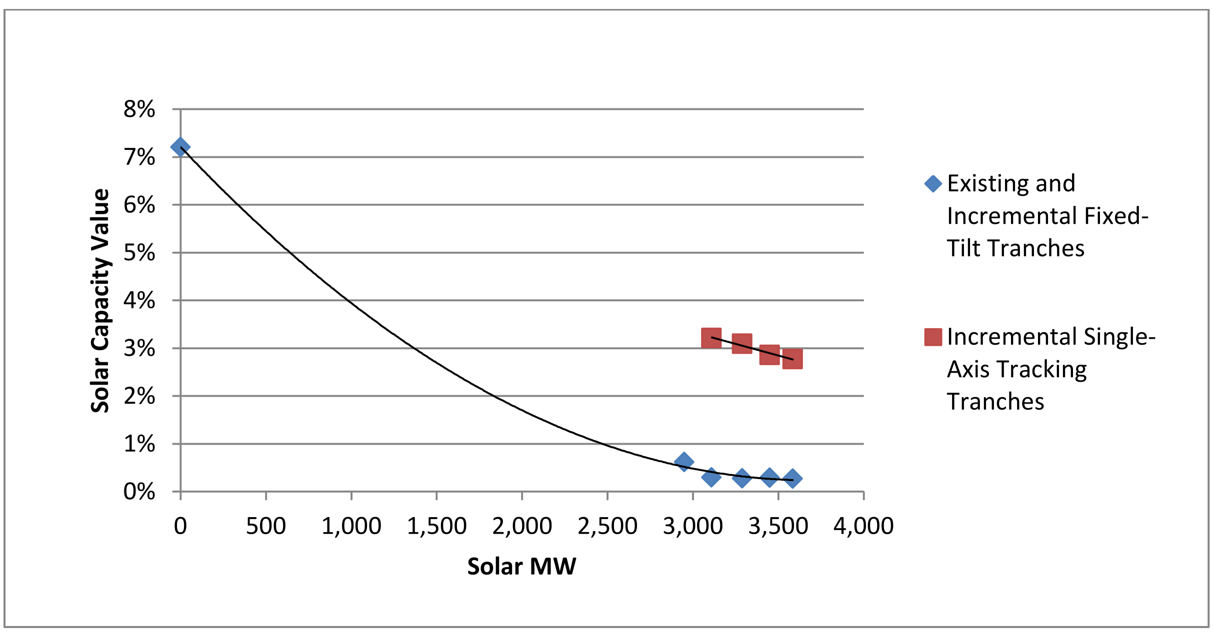
Table S6 shows results for DEP. As discussed earlier, the summer value proves to have very little weight in the annual value because over 90% of the LOLE occurs in the winter. By the time the 2,950 MW of existing and transition solar come online, the annual capacity value has already decreased substantially.

Table S6. DEP Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEP - 0 Solar	1.2%	35.4%	7.2%
2,950	2,950	DEP - 2950 Existing + Transition	0.6%	12.4%	0.6%
160	3,110	DEP - Tranche 1 - Fixed	0.3%	12.2%	0.3%
180	3,290	DEP - Tranche 2 - Fixed	0.3%	11.6%	0.3%
160	3,450	DEP - Tranche 3 - Fixed	0.2%	8.8%	0.3%
135	3,585	DEP - Tranche 4 - Fixed	0.2%	8.2%	0.3%
160	3,110	DEP - Tranche 1 - Tracking	3.2%	22.3%	3.2%
180	3,290	DEP - Tranche 2 - Tracking	3.1%	20.6%	3.1%
160	3,450	DEP - Tranche 3 - Tracking	2.8%	16.2%	2.9%
135	3,585	DEP - Tranche 4 - Tracking	2.7%	15.3%	2.8%

Figure S4 shows the DEP capacity values as a function of solar capacity.

Figure S4. DEP Annual Capacity Value by Solar Penetration



Fixed-Tilt vs. Single-Axis-Tracking

The differences in the single-axis-tracking and the fixed-tilt capacity values are illustrated in the July and January DEC profiles shown in the following figures. The additional output seen in the tracking in the early and late afternoon hours give it additional capacity value.

Figure S5. Average July Profiles

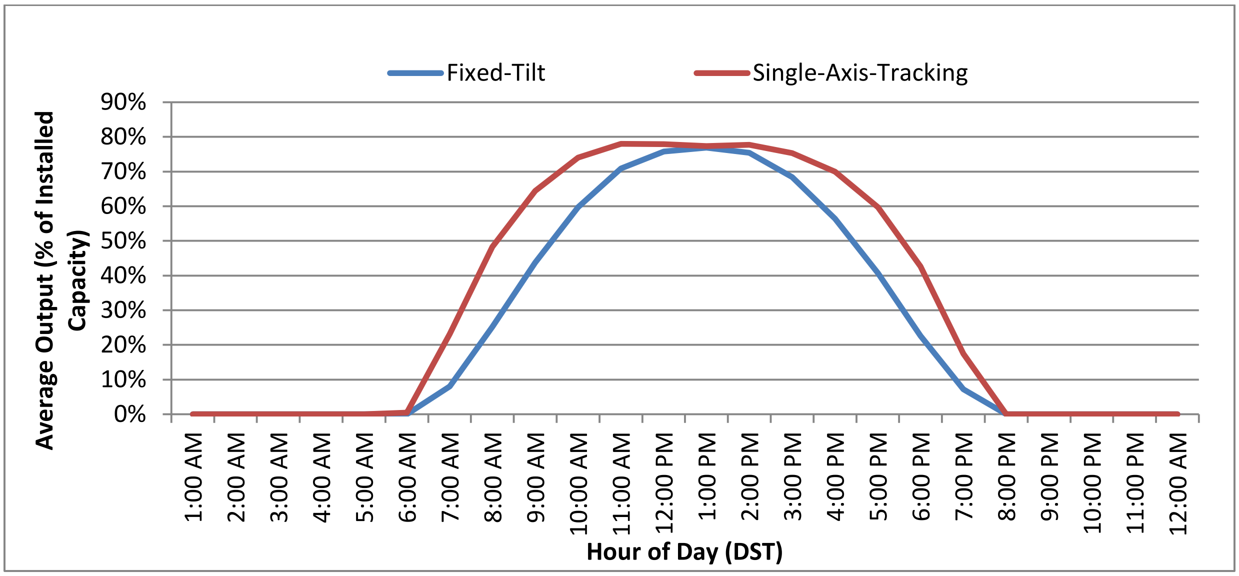
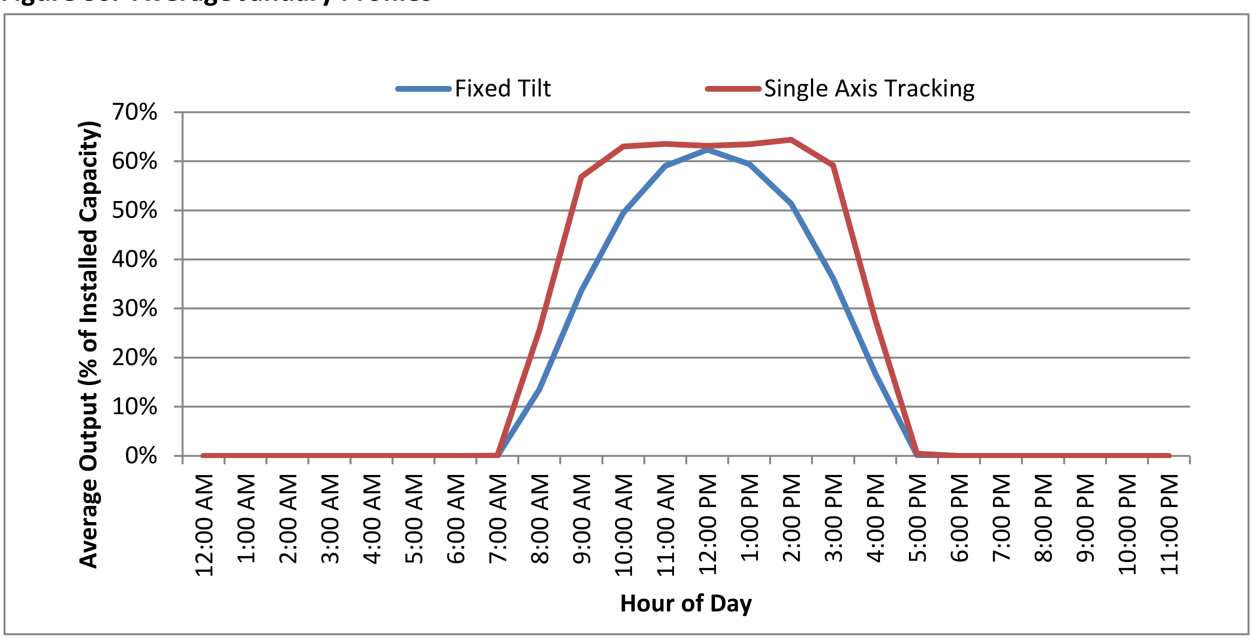


Figure S6. Average January Profiles



In summary, the winter LOLE to summer LOLE ratio drives the annual solar equivalent capacity values. Because the companies have higher winter LOLE values in hours when solar is not available, the resulting equivalent annual solar capacity values are significantly reduced. As solar penetration increases, the capacity values decrease further since the firm load shed events are shifted even further into hours when there is less solar output. However, single-axis-tracking resources do bring some additional capacity value compared to fixed-tilt resources due to more output in morning and evening hours.

II. Model Inputs and Setup

The following sections include a discussion on the major modeling inputs included in the Solar Capacity Value Study with an emphasis on loads and solar shapes.

A. Load Forecasts and Load Shapes

Table 1 displays the modeled seasonal peak forecast net of energy efficiency programs and behind the meter solar for 2020 for both DEC and DEP. The 2020 winter forecast for DEP is approximately 650 MW higher than the summer forecast which drives Loss of Load Expectation (LOLE) to be higher in the winter. In DEC, the winter forecast is approximately 340 MW less than the summer forecast making DEC's LOLE not as heavily weighted in the winter.

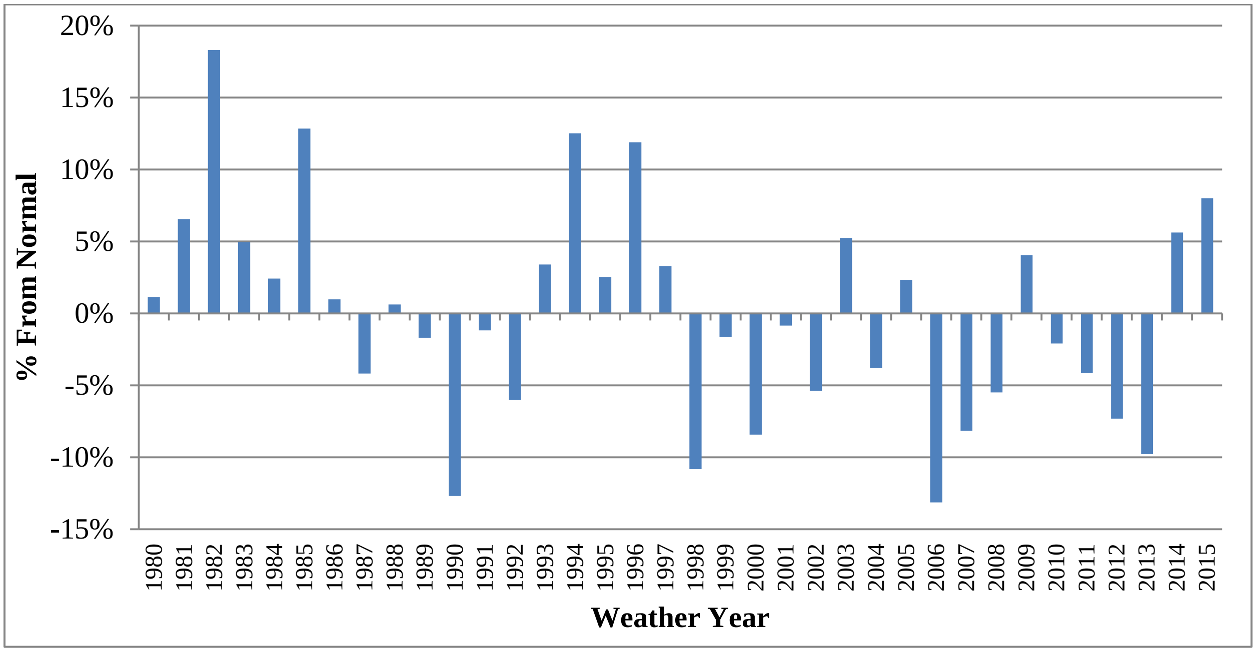
Table 1. 2020 Peak Load Forecast

	DEC	DEP East	DEP West	Coincident DEP
2020 Summer	18,260 MW	12,503 MW	828 MW	13,289 MW
2020 Winter	17,924 MW	12,866 MW	1,128 MW	13,946 MW

To model the effects of weather uncertainty, 36 historical weather years (1980 - 2015) were developed to reflect the impact of weather on load. These were the same 36 load shapes used in the 2016 Resource Adequacy Study. Based on historical weather and load, a neural network program was used to develop relationships between weather observations and load. Different weather to load relationships were built for each month. These relationships were then applied to the last 36 years of weather to develop 36 load shapes for 2020. Equal probabilities were given to each of the 36 load shapes in the simulation. The load shapes were scaled to align the normal summer and winter peaks to the Company's projected load forecast for 2020. Thus the "normal" summer peak reflects an average of the summer peak demands from the 36 load shapes. Similarly, the "normal" winter peak reflects an average of the winter peak demands from the 36 load shapes.

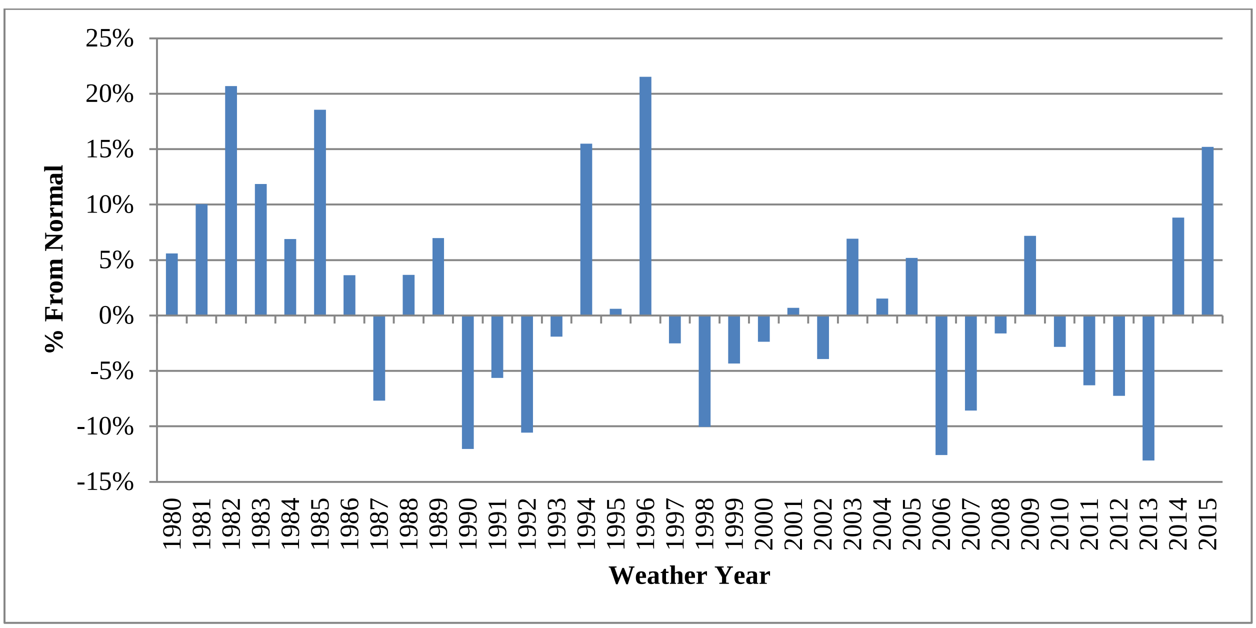
The figures below show the results of the weather load modeling by displaying the peak load variance for both the summer and winter seasons for each company. The y-axis represents the percentage deviation from the average peak. For example, a simulation using the 1985 DEC load shape would result in a summer peak load approximately 4.7% below normal and a winter peak load approximately 12.9% above normal. Thus, the bars represent the variance in projected peak loads for 2020 based on weather experienced during the historic weather years. It should be noted that the variance for winter is much greater than summer. Extreme cold temperatures can cause load to spike from additional electric strip heating. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation. Based on the neural net modeling, the figures show that DEC and DEP summer peak loads can be almost 8% higher than the forecast due to weather alone, while winter peak can be about 18% higher than the forecast for DEC and more than 20% higher than the forecast for DEP in an extreme year.

Figure 1. DEC Winter Peak Weather Variability



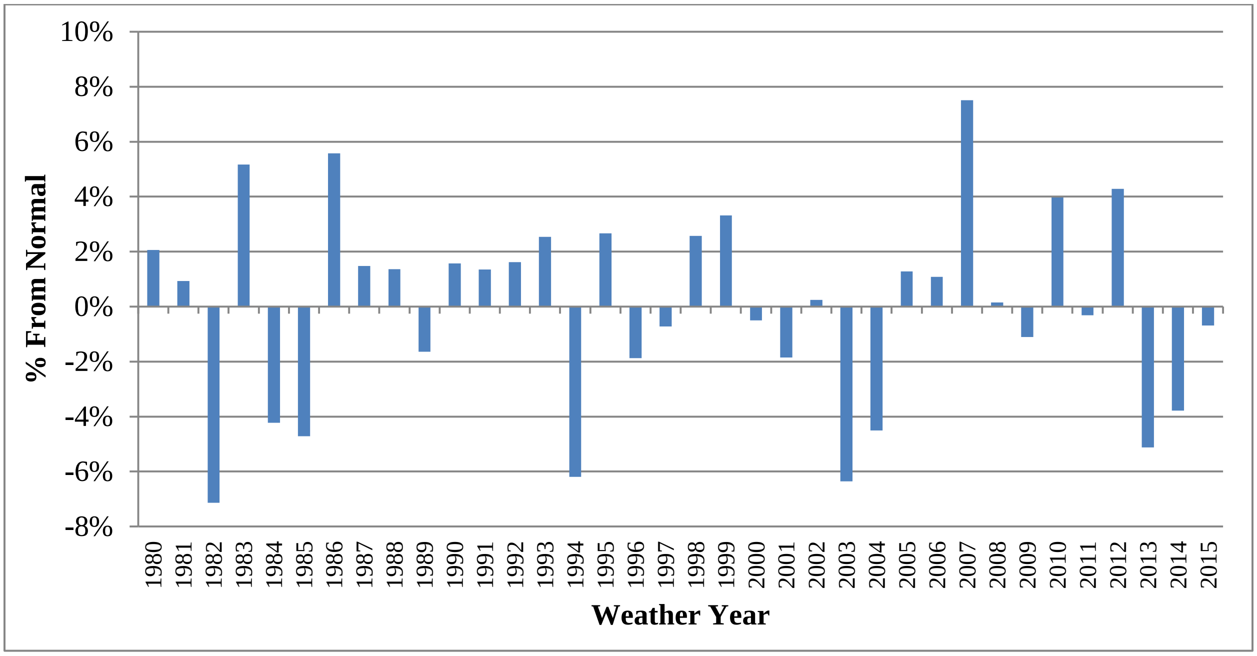
Note: The peak load is impacted by the day of week the lowest temperature occurred. Therefore, the loads are not always in the same order as the min temperature ranking.

Figure 2. DEP Winter Peak Weather Variability



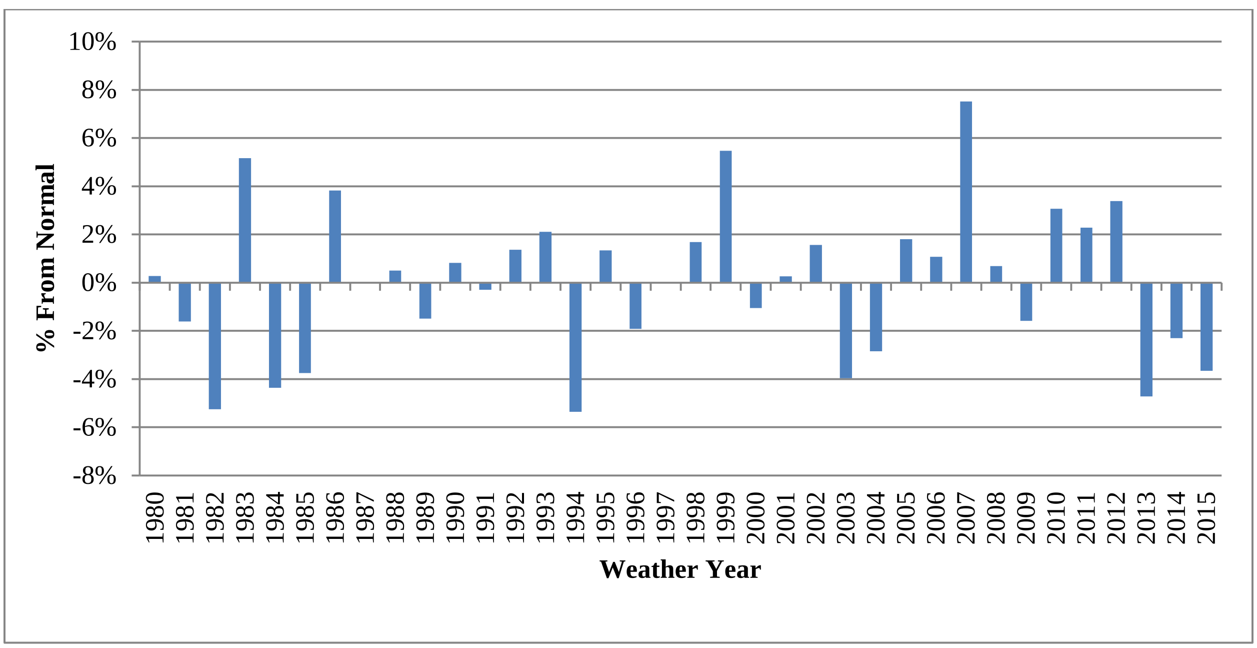
Note: The peak load is impacted by the day of week the lowest temperature occurred. Therefore, the loads are not always in the same order as the min temperature ranking.

Figure 3. DEC Summer Peak Weather Variability



Note: The peak load is impacted by the day of week the highest temperature occurred. Therefore, the loads are not always in the same order as the max temperature ranking.

Figure 4. DEP Summer Peak Weather Variability



Note: The peak load is impacted by the day of week the lowest temperature occurred. Therefore, the loads are not always in the same order as the min temperature ranking.

Economic Load Forecast Error

Economic load forecast error multipliers were developed to isolate the economic uncertainty that the Companies have in their 3 year ahead load forecasts. Three to five years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate economic load forecast error, the difference between Congressional Budget Office (CBO) GDP forecasts 3 years ahead and actual data was fit to a normal distribution. Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 4 shows the economic load forecast multipliers and associated probabilities. As an illustration, 7.9% of the time, it is expected that load will be under-forecasted by 4%. Within the simulations, when DEC under-forecasts load, the external regions also under-forecast load. The SERVM model utilized each of the 36 weather years and applied each of these five load forecast error points to create 180 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 2. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.96	7.9%
0.98	24.0%
1.00	36.3%
1.02	24.0%
1.04	7.9%

B. Solar Shape Modeling

Table 3 lays out the solar capacity levels that were analyzed in the study along with the inverter loading ratios (ILR) assumed. The existing and transition capacity includes 840 MW in DEC and 2,950 MW in DEP. As discussed earlier, loads were already reduced for behind the meter solar. This capacity included utility-owned-generation, PURPA generation and additional expected solar capacity called transition capacity. The tranches of solar analyzed assumed 75% of the capacity was fixed-tilt and 25% was single-axis-tracking capacity all with a 1.4 inverter loading ratio.

Table 3. Solar Capacity Penetration Levels

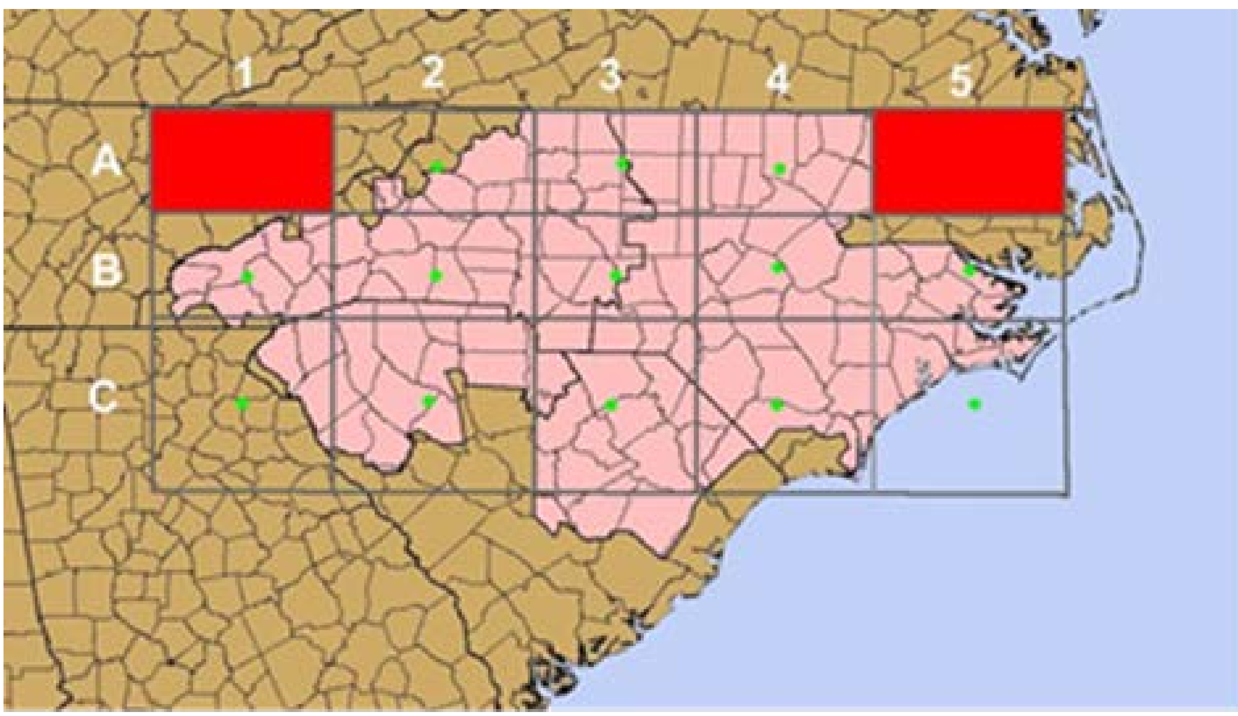
	DEC MW	DEP MW
Existing	679	1,923
Transition	161	1,027
Existing Plus Transition	840	2,950

Type	Technology	Inverter Loading Ratio	DEC MW	DEP MW
Existing: Utility Owned	Fixed-Tilt	1.4	130	154
Existing: Standard PURPA	Fixed-Tilt	1.3	549	1,769
Transition	Fixed-Tilt	1.43	121	770
Transition	Single-Axis Tracking	1.3	40	257
Total Existing Plus Transition			840	2,950

Tranche	Technology	Inverter Loading Ratio	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
Tranche 1	75% fixed/25% Tracking	1.4	680	680	160	160
Tranche 2	75% fixed/25% Tracking	1.4	780	1,460	180	340
Tranche 3	75% fixed/25% Tracking	1.4	780	2,240	160	500
Tranche 4	75% fixed/25% Tracking	1.4	420	2,660	135	635

Fixed and tracking solar profiles for the 36 weather years were developed in detail for each grid as shown in Figure 5.

Figure 5. Solar Profile Locations



Data was downloaded from the NREL National Solar Radiation Database (NSRDB) Data Viewer using the 13 latitude and longitude locations, detailed in Table 4, for the available years 1998 through

2015. Solar shapes were developed for the 1980 - 1997 time-frame by matching the closest peak load day from the two periods (1980 - 1997, 1998 - 2015) and using the same daily solar profile that was developed from the NREL dataset. An additional five solar shapes were calculated as variations of the "Actual Closest" peak load day to create additional variability among the solar shapes. The shapes were calculated by sorting the peak loads for the proper day (actual day +/- 1 day) in ascending order and offsetting the closest daily load shapes by choosing the days that most closely matched the load profiles plus or minus 1 or 2 days.

Table 4. Locations for Solar Profiles

Description	Latitude	Longitude
A2	36.13	-81.70
A3	36.17	-80.02
A4	36.09	-78.62
B1	35.33	-83.34
B2	35.41	-81.70
B3	35.41	-80.10
B4	35.45	-78.66
B5	35.41	-76.86
C1	34.57	-83.46
C2	34.53	-81.74
C3	34.49	-80.18
C4	34.45	-78.66
C5	34.57	-76.90

The solar capacity for DEP and DEC were modeled across the 13 location grid as follows:

Table 5. DEP Solar by Location

	Utility Owned	Standard PURPA	Transition	Transition	Tranche 1-4
Technology (Fixed-tilt/Tracking)	Fixed	Fixed	Fixed	Tracking	Fixed/Tracking
DC/AC Ratio	1.4	1.3	1.43	1.3	1.4
Capacity MW	154	1769	770	257	160 - 635

Location Breakdown					
A2	0%	0%	0%	0%	0%
A3	0%	1%	1%	1%	1%
A4	20%	23%	14%	14%	14%
B1	0%	1%	1%	1%	1%
B2	0%	0%	0%	0%	0%
B3	7%	9%	7%	7%	7%
B4	14%	26%	8%	8%	8%
B5	11%	8%	9%	9%	9%
C1	0%	0%	0%	0%	0%
C2	0%	0%	1%	1%	1%
C3	23%	6%	35%	35%	35%
C4	23%	23%	21%	21%	21%
C5	1%	3%	2%	2%	2%
Total	100%	100%	100%	100%	100%

Table 6. DEC Solar by Location

	Utility Owned	Standard PURPA	Transition	Transition	Tranche 1-4
Technology (Fixed-tilt/Tracking)	Fixed	Fixed	Fixed	Tracking	Fixed/Tracking
DC/AC Ratio	1.4	1.3	1.43	1.3	1.4
Capacity MW	130	549	121	40	680 - 2,660

Location Breakdown %

A2	15%	7%	3%	3%	3%
A3	6%	22%	22%	22%	22%
A4	0%	9%	2%	2%	2%
B1	0%	0%	0%	0%	0%
B2	47%	33%	12%	12%	12%
B3	6%	16%	26%	26%	26%
B4	0%	1%	1%	1%	1%
B5	0%	0%	0%	0%	0%
C1	0%	1%	0%	0%	0%
C2	0%	7%	27%	27%	27%
C3	25%	2%	5%	5%	5%
C4	0%	1%	1%	1%	1%
C5	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%

Figures 6 and 7 show the January average daily solar profiles for 1980 to 2015 for tracking and fixed technologies, respectively. The tracking files have more output in the earlier and later hours than the fixed profile which ultimately provides additional capacity value as shown in the results.

Figure 6. January Daily Tracking Solar Profile

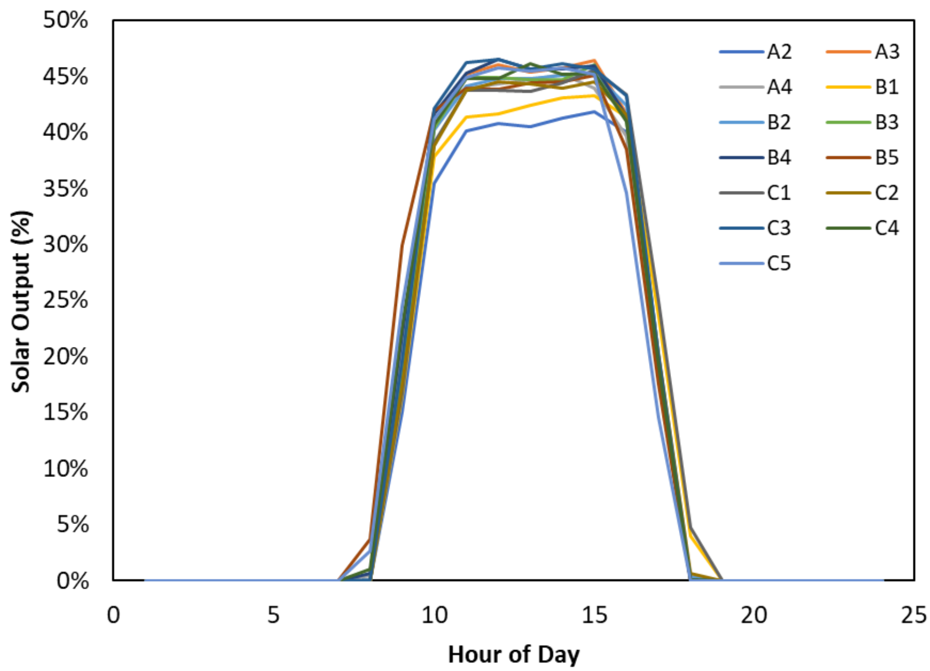
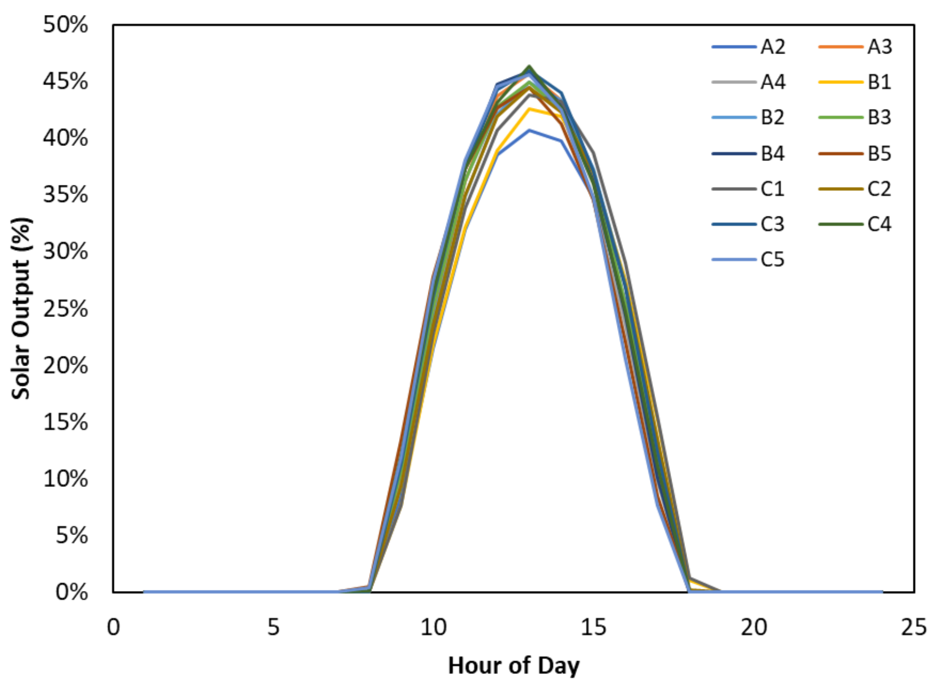


Figure 7. January Daily Fixed Solar Profile



Figures 8 and 9 show the August average daily solar profiles for 1980 to 2015 for tracking and fixed technologies, respectively.

Figure 8. August Daily Tracking Solar Profile

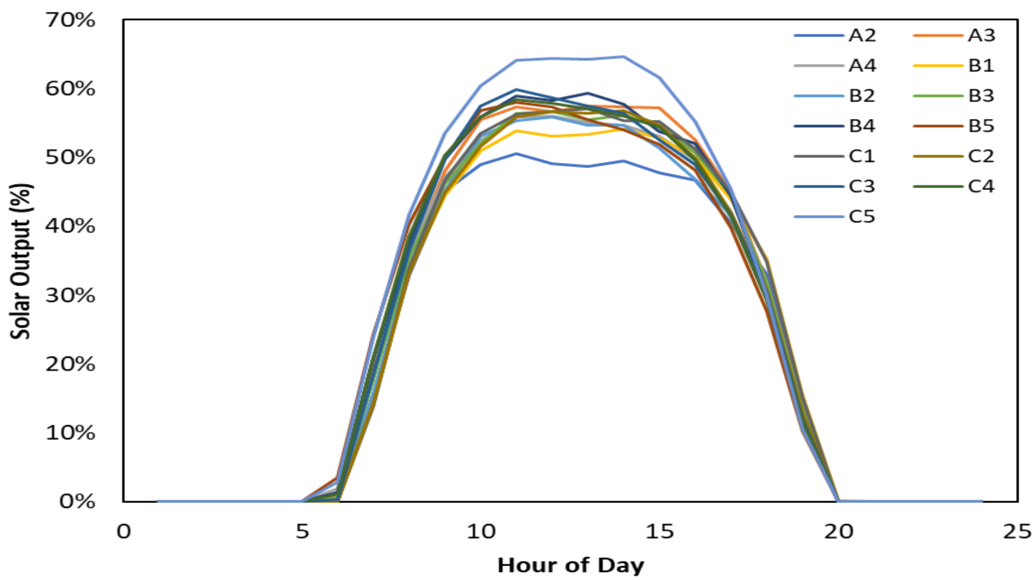
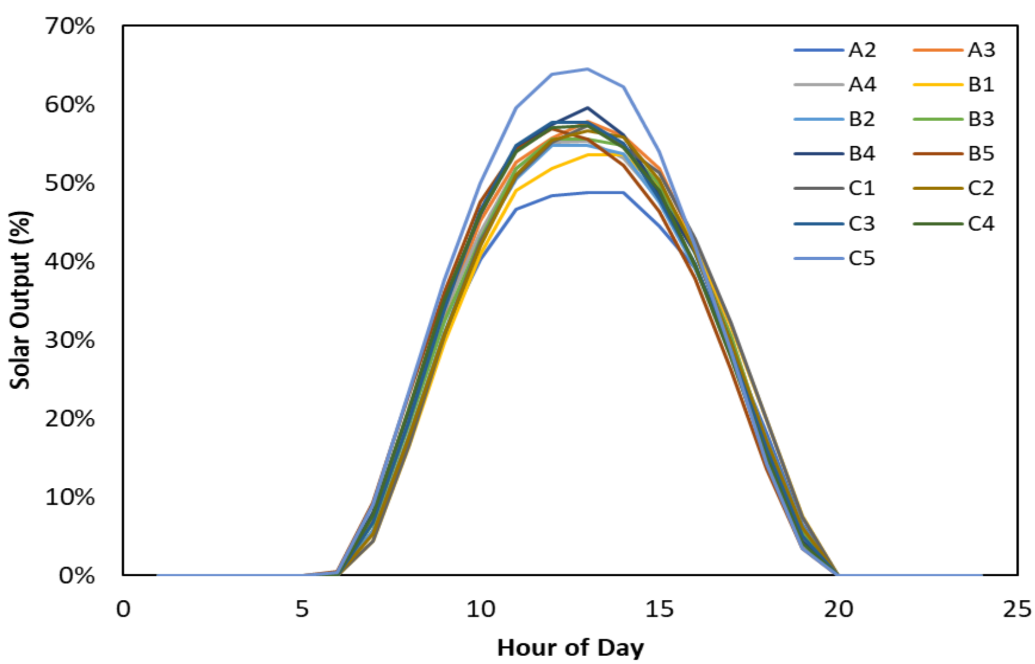


Figure 9. August Daily Fixed Solar Profile



C. Conventional Thermal Resources

Conventional thermal resources owned by the company and purchased as Purchase Power Agreements were modeled consistent with the 2020 study year. These resources are economically committed and dispatched to load. Similar to the resource adequacy study, the capacities of the units are defined as a function of temperature in the simulations allowing for higher capacities in the winter compared to the summer. Full winter rating is achieved at 35 °F.

The unit outage data for the thermal fleet in both Companies was based on historical Generating Availability Data System (GADS) data. Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar units. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods

Planned Outages
The actual schedule for 2019 was used.

To illustrate the outage logic, assume that from 2010 – 2014, a generator had 15 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

For neighboring regions, Astrapé used some of its in-house Time-to-Fail and Time-to-Repair distributions to capture a reasonable EFOR in each external region. The average EFOR in external regions was approximately 5%. Additional cold weather penalties were not included in the analysis.

Planned maintenance events are modeled separately and dates are entered in the model representing a typical year. For external resources, a 5% maintenance rate was applied to all units, and SERVM scheduled maintenance events which minimized the impact on reliability.

D. Hydro and Pump Storage Modeling

The hydro portfolios in DEC and DEP are modeled in segments that include Run of River (ROR) and Scheduled (Peak Shaving). The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. By modeling the hydro resources in these two segments, the model captures the appropriate amount of capacity dispatched during peak periods. On average, the DEC hydro generates 400 - 600 MW during peak conditions while DEP generates approximately 200 MW during peak conditions.

In additional to conventional hydro, DEC owns and operates a pump hydro fleet that includes expected upgrades to be made by 2020. The total capacity included was 2,400 MW. (1) Bad Creek at a 1,620 MW summer/winter rating and (2) Jocassee at a 780 MW summer/winter rating. These resources are modeled with reservoir capacity, pumping efficiency, pumping capacity, generating capacity, and forced outage rates. SERVM uses excess capacity to economically fill up the reservoirs to ensure the generating capacity is available during peak conditions.

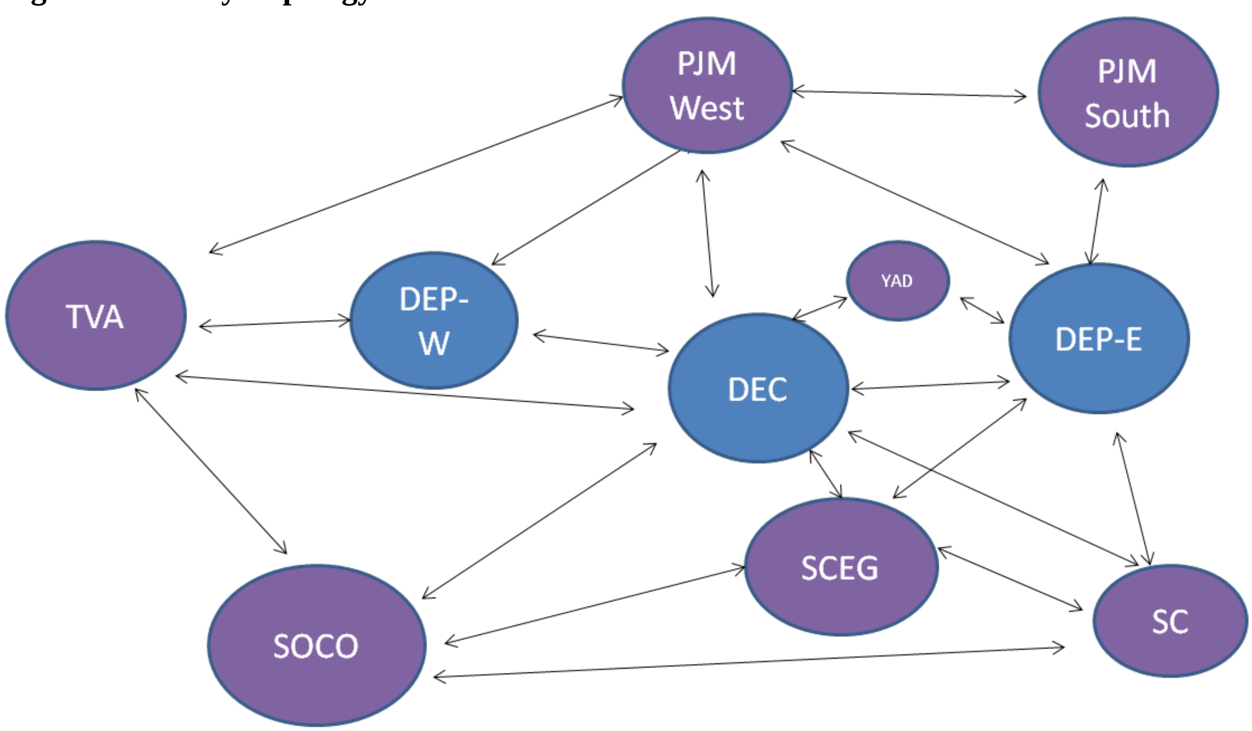
E. Demand Response Modeling

Demand response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints. For 2020, DEC assumed 1,031 MW of demand response in the summer and 406 MW in the winter. DEP assumed 1,015 MW of summer capacity and 512 MW of winter capacity.

F. Topology and Neighbor Assistance

Consistent with the Company's Resource Adequacy Study, Figure 10 shows the study topology that was used for the study. To thoroughly quantify resource adequacy, it is important to capture the load diversity and generator outage diversity that a system has with its neighbors. For this study, the DEC and DEP systems were modeled with seven surrounding regions. The surrounding regions captured in the modeling included Tennessee Valley Authority (TVA), Southern Company (SOCO), PJM West, PJM South, Yadkin (YAD), South Carolina Electric & Gas (SCEG), and Santee Cooper (SC). SERVM uses a pipe and bubble representation in which energy can be shared based on economics but subject to transmission constraints. Loads for each external region were developed in a similar manner as the DEC loads. A relationship between hourly weather and publicly available hourly load was developed based on recent history, and then this relationship was applied to 36 years of weather data to develop 36 load shapes. Resources in each external region were added to achieve reasonable reliability in surrounding regions.

Figure 10. Study Topology



G. Firm Load Shed Event

A firm load shed event is calculated by the model as any day whether it is one hour or ten hours that resources could not meet load even after utilizing neighbor assistance and demand response programs. Regulating reserves of 216 MW in DEC and 134 MW in DEP were always maintained.

III. Simulation Methodology

Since firm load shed events are high impact, low probability events, a large number of scenarios must be considered to accurately project these events. For this study, SERVM utilized 36 years of historical weather and load shapes, 5 points of economic load growth forecast error, 6 differing solar shape patters, and 15 iterations of unit outage draws for each scenario to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 36 weather years * 5 load forecast errors * 15 unit outage iterations * 6 solar profiles = 16,200 total iterations for each level of solar penetration simulated. Weather years and solar profiles were each given equal probability while the load forecast error multipliers were given their associated probabilities as reported in the input section of the report. This framework was simulated for each of the solar penetration levels in the following table.

Table 7. Solar Penetration Levels

	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
0 MW Level	-	-	-	-
Existing Plus Transition MW	840	840	2,950	2,950
Tranche 1	680	1,520	160	3,110
Tranche 2	780	2,300	180	3,290
Tranche 3	780	3,080	160	3,450
Tranche 4	420	3,500	135	3,585

Consistent with the reserve margin study, a Loss of Load Expectation for each Company is calculated and both DEC and DEP systems were targeted to approximately 0.1 events per year[3]. This is also referred to as the 1 day in 10-year standard. The LOLE may occur in the winter or the summer but as was seen in the 2016 Resource Adequacy Study, the winter LOLE has increased compared to the summer LOLE within both Companies due to cold weather uncertainty, and an increase in solar capacity. As solar is added to the system, a higher percentage of the LOLE will occur in the winter because the output of solar in the summertime during peak load hours (afternoon and early evening hours) is naturally higher than the output during the winter peak load hours which occur early in the morning or late in the evening. In other words, when 1 MW of solar is added to the system, the 1 MW of solar reduces summer LOLE more than it reduces winter LOLE.

Once the timing of each firm load shed event is projected by SERVM. The solar profile is overlaid onto the loss of load events and the probability weighted solar contribution during those loss of load events is calculated. The minimum solar output seen during an hour with load shed is the output that is attributed to the capacity value calculation for each firm load shed event. For example, if an event lasted from hour 7 to hour 10 in the winter, and a 100 MW solar resource produced 0 MW in hour 7, 5 MW in hour 8, 20 MW in hour 9 and 40 MW in hour 10, then the addition of that solar resource did not remove the event because there was still load shed in hour 7. For this example, the 0 MW of output would be included in the capacity value calculation.

[3] The different penetration levels were between 0.09 LOLE and 0.11 LOLE as it is difficult to get exactly to 0.1 as different size units are added and removed.

IV. Results

Table 8 shows the seasonal LOLE by Company for the different solar penetration levels. Both companies have higher load uncertainty in the winter due to extreme weather, and lower demand response resources in the winter compared to the summer, causing more winter LOLE than summer LOLE. DEP's winter peak forecast is approximately 650 higher than its summer forecast and has substantially more existing plus transition solar than DEC, giving DEP a higher LOLE winter weighting compared to DEC. By the time tranche 4 solar is added each company, there is little to no summer LOLE risk as DEC winter LOLE represents 93% of the total LOLE and DEP winter LOLE represents 99.7% of the total LOLE.

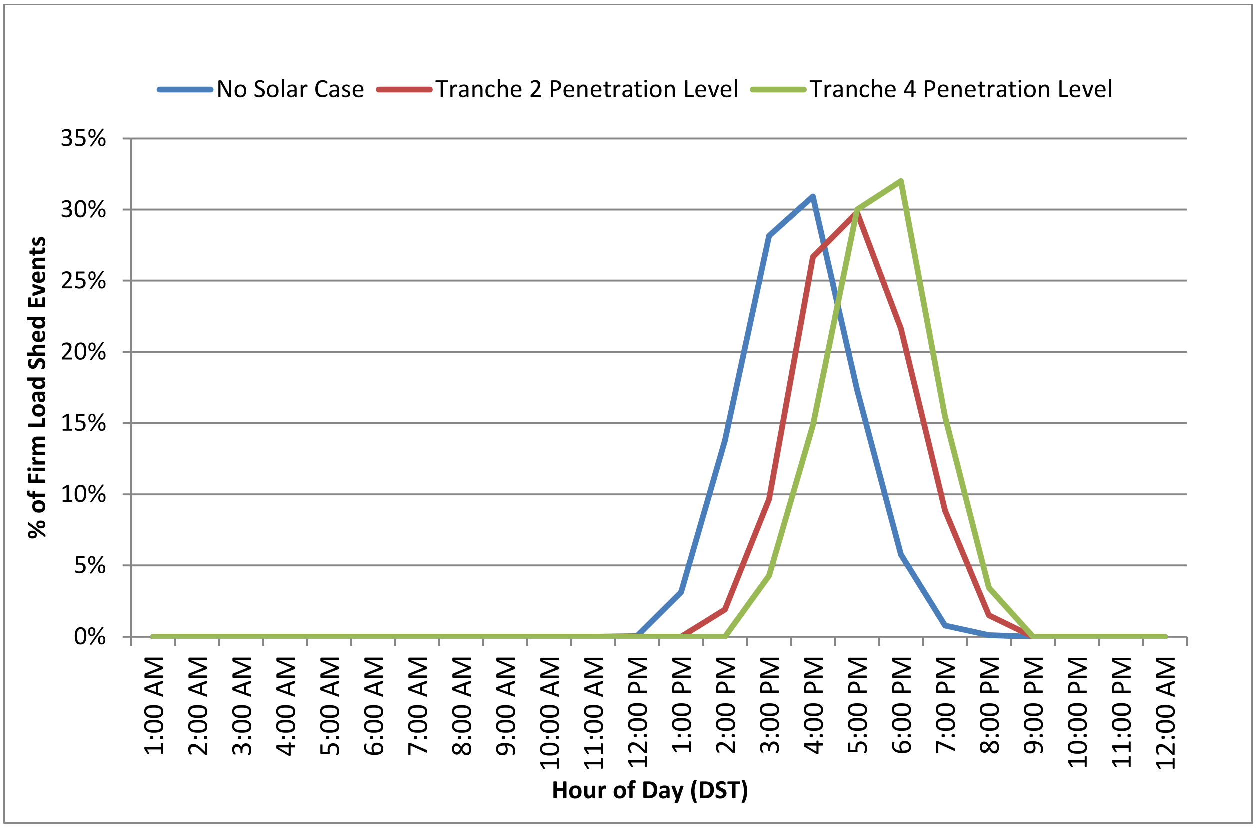
Table 8. DEC and DEP Seasonal LOLE %

	DEC Incremental Solar	DEC Cumulative Solar	DEC LOLE	DEC LOLE	DEP Incremental Solar	DEP Cumulative Solar	DEP LOLE	DEP LOLE
	MW	MW	Summer %	Winter %	MW	MW	Summer %	Winter %
0 MW Level	-	-	59%	41%	-	-	14.7%	85.3%
Existing Plus Transition MW	840	840	31%	69%	2950	2,950	0.6%	99.4%
Tranche 1	680	1,520	21%	79%	160	3,110	0.5%	99.5%
Tranche 2	780	2,300	11%	89%	180	3,290	0.4%	99.6%
Tranche 3	780	3,080	7%	93%	160	3,450	0.3%	99.7%
Tranche 4	420	3,500	7%	93%	135	3,585	0.3%	99.7%

The seasonal LOLE table alone allows for a reasonable approximation of the annual capacity value of solar resources. For example, assuming that solar receives a 50% value in the summer and a 5% value in the winter (similar to previous company estimates), then the annual ELCC for DEP at Tranche 4 could be estimated using the following formula: 5% winter value * 99.7% winter LOLE weighting + 50% summer value * 0.3% summer LOLE weighting = 5.1%. While this simplified approach captures the appropriate seasonal LOLE, it misses the timing of the events across the day in each season as solar penetration grows, so the approximate calculations will not exactly match the values derived from the simulations.

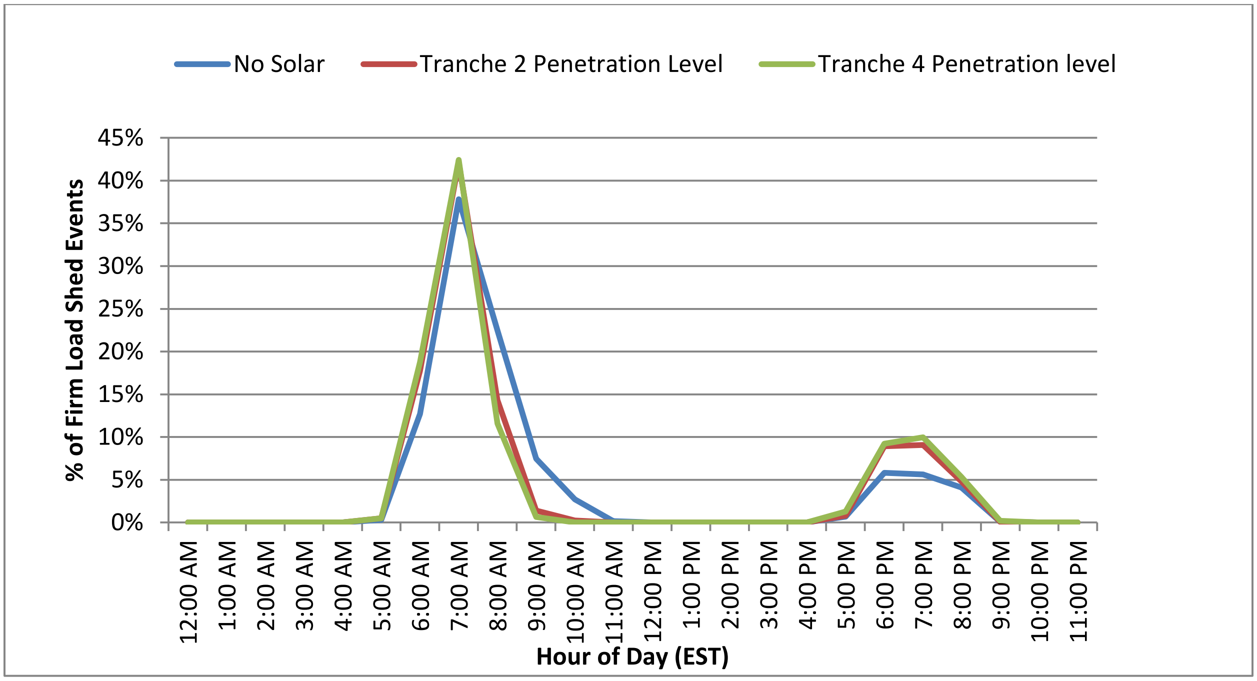
To illustrate further, the following figure shows the percentage of firm load shed events in DEC by hour of day in the summertime for the zero level solar and two additional solar penetration levels. This figure shows how peak net load shifts outward across different solar penetration levels. Before large additions of solar are added, both Companies experience load shed events during the 1 pm to 6 pm timeframe in the summer with the highest concentration between 3 pm and 5 pm. As solar capacity is added, the peak net load and therefore firm load shed hours are pushed out to later in the day when the solar is not able to produce as much output. By the time Tranche 4 has been included, the more concerning hours of the day are from hour 3 pm to 8 pm. This impact lowers the summer solar capacity value as solar penetration increases.

Figure 11. Summer Firm Load Shed Events by Hour of Day



A similar pattern is seen in the winter season as shown in Figure 12. The percentage of firm load shed events are plotted as function of time of day. Typically, LOLE events occur in the early morning and late evening hours when little solar output is available. As solar penetration increases, the net load becomes lower between 8 am and 5 pm causing more of the LOLE to be concentrated in the 7 am hour when the solar has lower output. This is a subtle shift but explains the slight decrease in winter capacity value as solar penetration increases.

Figure 12. Winter Firm Load Shed Events by Hour of Day



By modeling thousands of iterations in a Monte Carlo Model with 36 different weather years in SERVM, both the seasonal and hourly pattern change is captured across the different solar penetration levels. As solar increases, system LOLE shifts more heavily to the winter and capacity value declines because the firm load shed events begin to fade during solar hours and become more prominent during hours with lower solar output.

Table 9 shows the final DEC solar capacity value results for each penetration level. The first MW of solar in DEC is worth 27% in annual capacity value but after 840 MW are added, the next MW is worth 11% in annual capacity value. The fixed-tilt solar and the single-axis-tracking were evaluated separately with each additional tranche. The results show that at Tranche 1, the fixed-tilt solar has a 6.5% annual capacity value while Tranche 4 is reduced to 1.2%. The single-axis-tracking solar ranges from 10.9% to 2.9% from Tranche 1 to Tranche 4 on an annual basis. A steady decline in capacity value is seen across the winter and summer as the penetration increases just due to the firm load shed hours shifting to hours with less solar output and the seasonal LOLE weighting shifting more to the winter.

Table 9. DEC Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEC - 0 Solar	2.5%	44.65%	27.2%
840	840	DEC - 840 Existing + Transition	0.9%	33.6%	11.1%
680	1,520	DEC - Tranche 1 - Fixed	0.5%	29.5%	6.5%
780	2,300	DEC - Tranche 2 - Fixed	0.4%	23.1%	2.9%
780	3,080	DEC - Tranche 3 - Fixed	0.2%	19.4%	1.6%
420	3,500	DEC - Tranche 4 - Fixed	0.2%	14.6%	1.2%
680	1,520	DEC - Tranche 1 - Tracking	2.0%	45.3%	10.9%
780	2,300	DEC - Tranche 2 - Tracking	1.8%	36.6%	5.6%
780	3,080	DEC - Tranche 3 - Tracking	1.3%	31.9%	3.4%
420	3,500	DEC - Tranche 4 - Tracking	1.1%	25.6%	2.9%

Figure 13 shows the DEC results plotted as a function of solar capacity. This curve provides the annual capacity value of every incremental MW added to the system. The Existing MWs make up 840 MW and then the four tranches are added to that totaling 3,500 MW

Figure 13. DEC Capacity Value Results by Solar Penetration

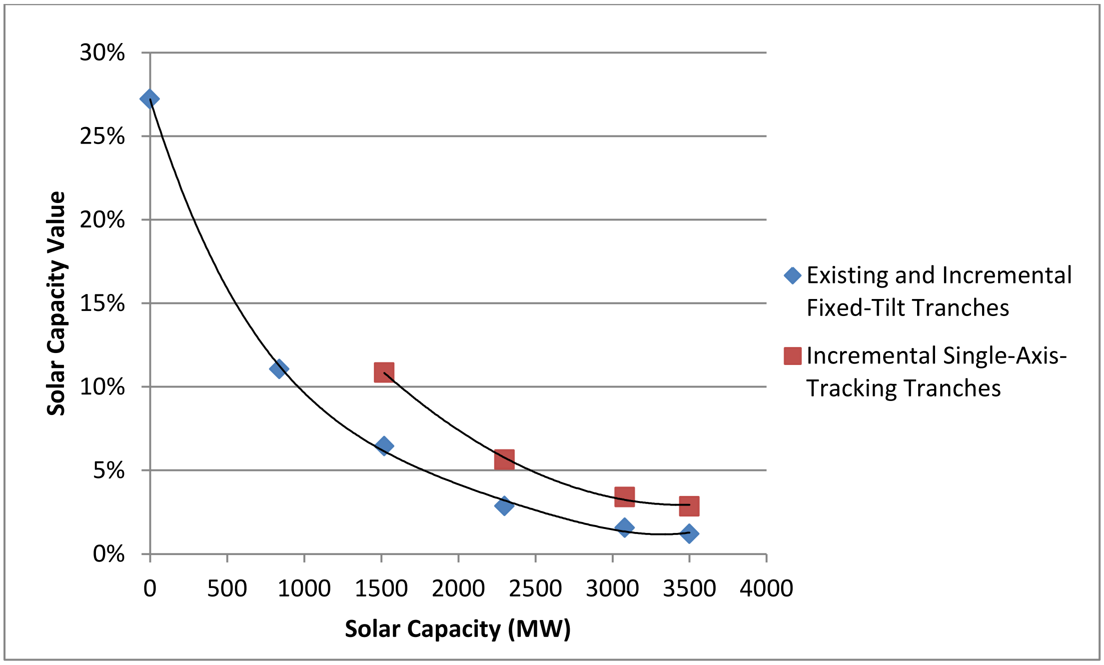


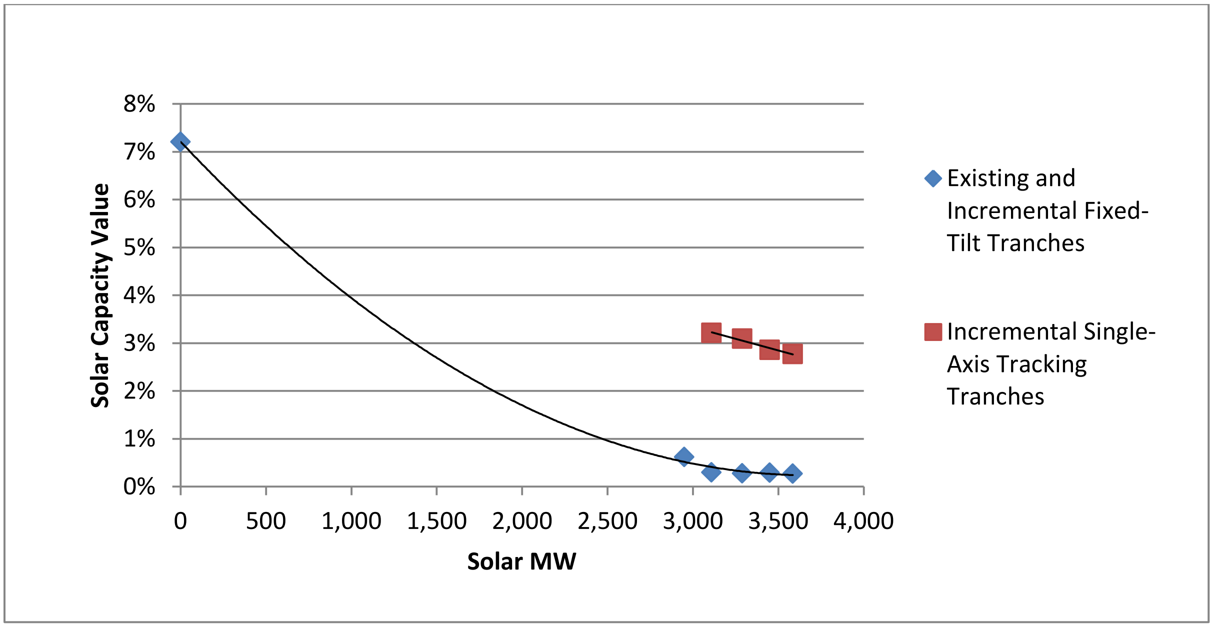
Table 10 shows solar capacity value results for DEP. As discussed earlier, the summer value proves to have very little weight in the annual value because over 90% of the LOLE occurs in the winter. Because the LOLE is so small in the summer for DEP, an additional simulation run was required which increased the load in DEP in only summer hours to surface enough reliability events to calculate the summer capacity value. By surfacing LOLE in the summer, accurate solar capacity values could be calculated although they still have little to no impact on the annual values.

Table 10. DEP Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEP - 0 Solar	1.2%	35.4%	7.2%
2,950	2,950	DEP - 2950 Existing + Transition	0.6%	12.4%	0.6%
160	3,110	DEP - Tranche 1 - Fixed	0.3%	12.2%	0.3%
180	3,290	DEP - Tranche 2 - Fixed	0.3%	11.6%	0.3%
160	3,450	DEP - Tranche 3 - Fixed	0.2%	8.8%	0.3%
135	3,585	DEP - Tranche 4 - Fixed	0.2%	8.2%	0.3%
160	3,110	DEP - Tranche 1 - Tracking	3.2%	22.3%	3.2%
180	3,290	DEP - Tranche 2 - Tracking	3.1%	20.6%	3.1%
160	3,450	DEP - Tranche 3 - Tracking	2.8%	16.2%	2.9%
135	3,585	DEP - Tranche 4 - Tracking	2.7%	15.3%	2.8%

Figure 14 shows the DEP capacity values as a function of solar capacity. The tranches are much smaller within the DEP region and therefore display little movement in the capacity value from tranche to tranche compared to the DEC results.

Figure 14. DEP Capacity Value Results by Solar Penetration



The differences in the tracking and the fixed-tilt capacity values are illustrated in the summer and winter profiles shown in the following figures. The additional output seen in the tracking in the early and late afternoon hours give it additional capacity value. As expected, the July profiles produce more output in the morning and early evening compared to the January profiles.

Figure 15. Average July Profiles

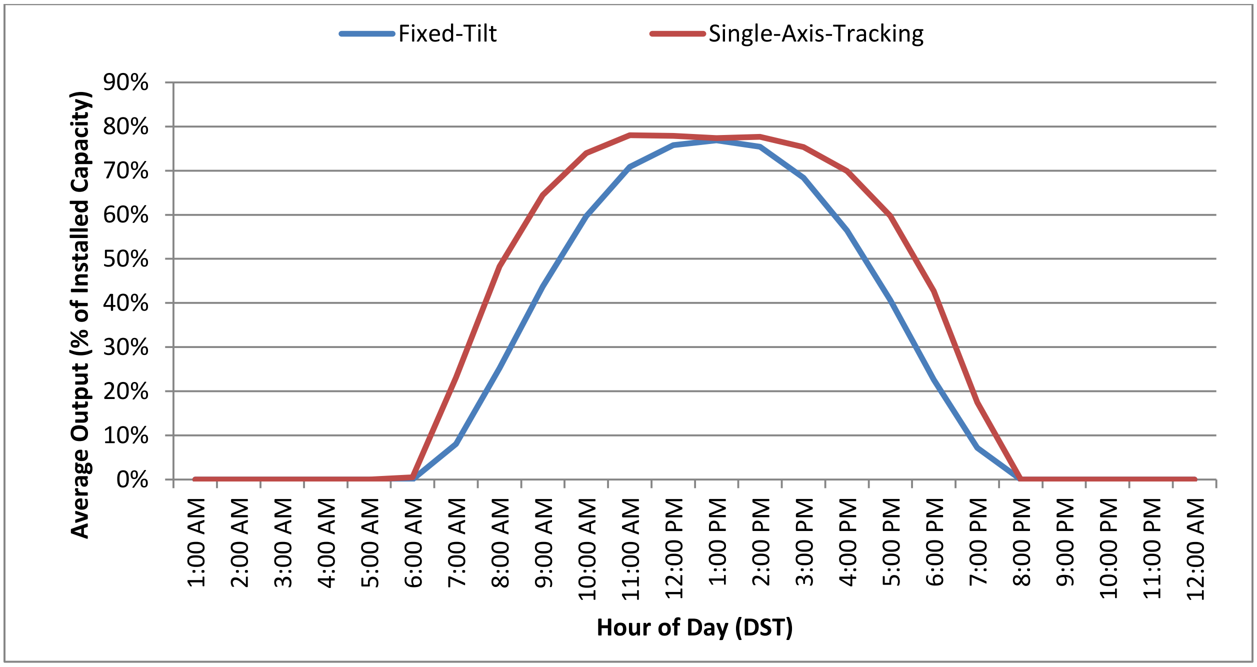
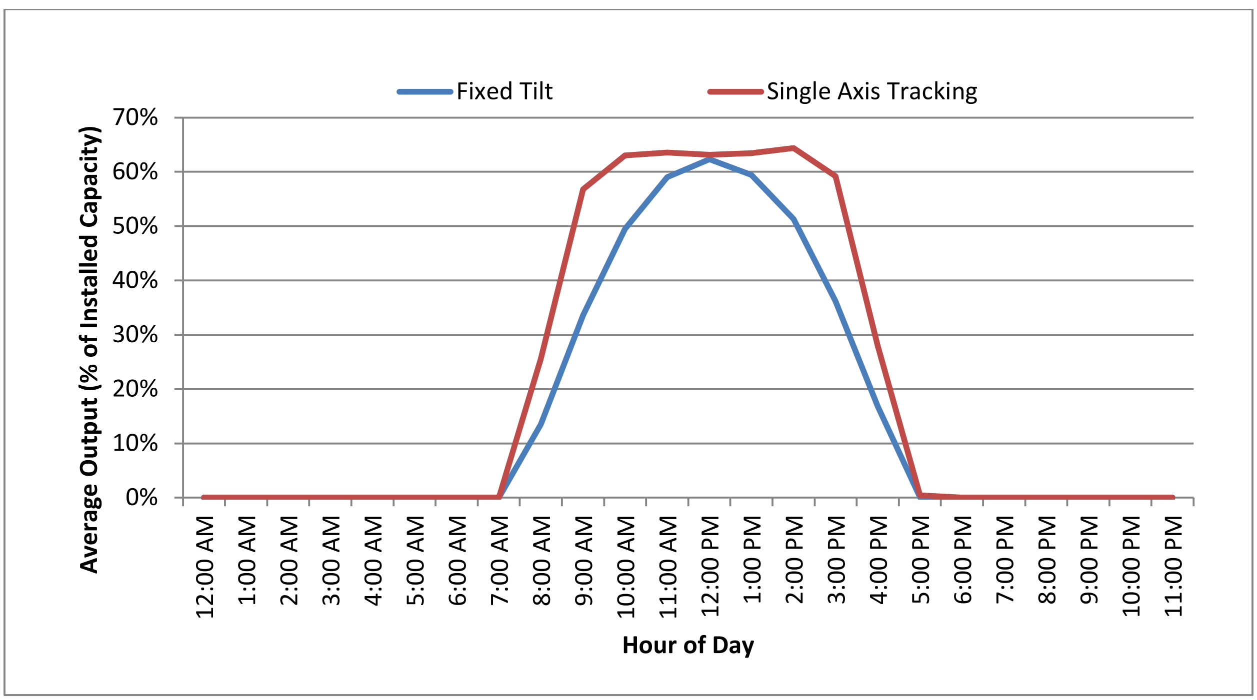


Figure 16. Average January Profiles



In summary, the following was seen in the study:

1. The winter LOLE to summer LOLE ratio is a major driver in the annual capacity values. The higher winter LOLE is driven by cold weather uncertainty and increases when solar capacity is added.

2. As solar penetration increases, the capacity values decrease further since the firm load shed events and net peak load are shifted to hours when there is less solar output.

3. Single-axis-tracking resources bring additional capacity value compared to fixed-tilt resources due to more output in morning and evening hours.